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BOILER MODIFICATION COST SURVEY FOR SULFUR OXIDES CONTROL BY FUEL SUBSTITUTION

ACUREX CORPORATION

PREPARED FOR
NATIONAL ENVIRONMENTAL RESEARCH CENTER

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16. ABSTRACT: The report gives results of a study to identify capital costs associated with converting industrial and utility boilers from conventional high-sulfur fossil fuels to low-sulfur products from selected coal conversion processes. The boilers of concern include all industrial and utility size equipment in the 10 to the 7th power to 10 to the 10th power Btu/hr capacity range. The substitute fuels include solvent refined coal (SRC) in the solid and hot liquid (melted) phases as well as lower-Btu gas. The cost assessment methods used in the study showed that conversion to liquid SRC is the most expensive alternative. Converting coal-fired boilers to solid SRC is the least expensive alternative for these types of boilers. Between the costs of converting to SRC in either phase lie those costs for converting to the gaseous fuels. A significant result of the study is that the costs of all conversion strategies increase exponentially with boiler capacity: cost appears to be a weak function of boiler design.

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This report has been reviewed by the Environmental Protection Agency and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

FOREWORD

This document presents the results of a survey of the costs of converting conventional, fossil fueled, stationary combustion equipment to the use of selected coal-derived fuels. The report provides updated information on present-day fuel switching activity, continues with the presentation of equipment conversion costs, and concludes with the formulation of cost models derived from the previously collected data.

The latter four authors of this report, personnel of The Coen Co. in Burlingame, California, performed the boiler modification cost assessments.

Aerotherm extends its appreciation for the valuable assistance provided by Mr. R. C. Carr of the Electric Power Research Institute, Palo Alto, California, and Dr. R. M. Jimeson of the Federal Power Commission, Washington, D.C. Special thanks is given to the diligent members of the Aerotherm Technical Publications Department.

This survey was performed for the Engineering Analysis Branch of the Control Systems Laboratory, U.S. Environmental Protection Agency. Dr. Gary J. Foley was the task officer until July 26, 1974. Dr. Charles Chatlynne was the task officer for the remainder of project's duration. The Aerotherm Project Manager was Dr. Larry W. Anderson. Dr. C. B. Moyer and Dr. H. B. Mason acted as advisors for all phases of the study. The study was undertaken during the months of June to September, 1974.

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SECTION 1

INTRODUCTION

The creation of the various combustion-generated chemical species generally regarded as air pollutants can be reduced by a variety of means. Some pollutants, such as "thermal" nitric oxide, lend themselves to reduction by modification of the combustion process. Others, notably the oxides of sulfur, are released in quantities directly proportional to the amount of some contaminant contained in the fuel. Pre- or post-combustion controls are the only feasible means of eliminating combustion systems as sources of SO_x. Therefore, the two leading strategies for controlling SO_x emissions from combustion equipment firing sulfur-containing fuels are: (1) burning desulfurized fuel, or (2) removing the SO_x from the flue gas (Reference 1-1).

For high-sulfur coal, the former method can be effected by burning the products from various gasification and liquefaction processes, while several popular scrubbing techniques exist for stack gas SO_x removal. The choice of the most viable control strategy will be based on cost, among other factors. Such monetary considerations are to be analyzed using detailed, consistent cost models developed by the EPA.

EPA has funded research into several stack gas scrubbing techniques, and has detailed information on the costs of such operations for a given size of installation. The costs associated with typical coal gasification and liquefaction processes are also reasonably well in hand (Reference 1-2). There is not, however, a good source of information on the costs associated with converting oil- and coal-fired equipment to use these "synthetic" gases and liquids as fuels. The purpose of this task order is to provide cost information on the conversion from conventional fossil fuels to selected coal-derived gaseous and liquid fuels as a function of equipment type and firing capacity. This study focuses on conventional stationary combustion systems, such as industrial furnaces and utility boilers. The cost figures collected during this study lead to the formulation of generalized equipment conversion cost models, compatible with existing models involving production and transportation of these coal-derived fuels. The results of this task will contribute to EPA's on-going SO_x Control Strategy Analysis.

Specifically, the coal-derived fuels of concern in the context of the present study include Solvent Refined Coal (SRC) and the range of low-Btu (150 Btu/scf) to high-Btu (1000 Btu/scf) content gases. For the gaseous fuels, an attempt is made to treat the range of gases as a continuum, and to incorporate a heating value term in the cost models for gas. Large-scale research and development programs aimed at determining the feasibility of using these materials as fuels have only recently been initiated. As a result, very little is known about their combustion and handling properties, and certain assumptions were made in this regard in order to make the required equipment modification cost estimates. It will be possible to evaluate these assumptions as more information on these fuels' physical properties becomes available.

The combustion systems of concern include steam-raising boilers in the 10^7 to 1000 x 10^7 Btu/hr range, encompassing all industrial and utility size equipment. This assures inclusion of the smaller SO_x sources, which tend to lack even intermittent controls (i.e., tall stacks) and which may have a significant impact on local air quality.

A future use for these coal-derived fuels for electric power production will be to fire them in combined-cycle plants, rather than solely in converted equipment of conventional designs. Indeed, the ultimate goal of most present-day coal-conversion power system projects is the demonstration on a commercial scale of an economically and environmentally acceptable electric generating plant that links a coal-conversion system with a combined-cycle plant adapted for using these exotic fuels (see References 1-3, 1-4, 1-5). Combined-cycle power plants are not, however, treated in the present study, but it is felt that determining the costs of converting conventional combustion equipment to the use of these fuels will provide support for future system trade-off and cost-effectiveness assessments.

The remainder of the present study is organized in the following manner:

Section 2: Current Fuel Substitution Activity - Conventional to Coal-Derived Fuels

This section attempts to draw together ongoing, practical experiences and state-of-the-art knowledge on the subject of converting the combustion equipment of concern to the use of exotic, coal-derived fuels from more conventional fossil fuels. This investigation was performed in the hope of supplementing the estimates of equipment conversion costs presented later in the study.

Section 3: Characterization of Combustion Equipment

This section presents the justification of the choice of combustion equipment types scrutinized in the study. Brief qualitative descriptions of the equipment are included.

Section 4: Characterization of Substitute Fuels

The study continues with brief discussions of the Solvent Refined Coal process, the notable coal gasification schemes, and their probable importance as fuels of the future. Typical chemical compositions of these fuels are given as well.

Section 5: Selection of Fuel Substitution Options

The manner in which the conversion cost data will be collected is introduced. This consists of a matrix of boiler type versus boiler capacity for a given type of conversion. The cost estimation method involves applying a set of cost data obtained from a similar conversion (i.e., to a lighter fuel oil) to a postulated coal-derived fuel conversion.

Section 6: Documented Boiler Conversion Cost Data

This section contains the estimated equipment conversion cost data for a given boiler type, original fuel and substitute fuel as set forth in the "Equipment Conversion Cost" data sheets. Included also are plots of the cost versus capacity data. Qualitative descriptions of the methodology of each conversion are provided. A discussion of the possible cost models that may be derived from these data is included as well.

Section 7: Conclusions and Recommendations

The significance of the results of the study are summed up, and recommendations for their future application are provided.

The report concludes with the References and the Appendix. The latter section contains the bulk cost data from which the final equipment conversion cost figures were derived. Included also is a tabulation of popular coal gasification processes. The appendix concludes with a table of British to metric conversion factors.

SECTION 2

CURRENT FUEL SUBSTITUTION ACTIVITY: CONVENTIONAL TO COAL-DERIVED FUELS

2.1 INTRODUCTION

Two energy source substitution strategies exist for reducing sulfur oxide emissions from fossil-fueled steam-generation equipment. First, the generating source itself may be replaced, such as switching from a fossil-fueled to hydropower plant. The second option, and by far the more expedient, is substitution of a cleaner fuel. The present study is concerned with a specialized case of the latter method.

Fuel substitution is a common practice in the operation of most large steam raising plants, although its motivation is most often based on fuel availability rather than on air pollution control. Most of these plants were originally designed for dual fuels, and the actual in-plant fuel switching process is usually quite straightforward. As a general rule, however, difficulty in doing so increases when progressing from gaseous or liquid to solid fuels. The material handling problems are worsened, and the possibility of additional combustion erratics arise with reduced fuel heating value.

Among the more promising low-sulfur fossil fuels are the products from coal conversion processes. The current clean fuel shortage has sparked widespread interest in the energy generation potential of these future fuels. At the present time, however, no existing industrial or utility boiler is firing these fuels, due mainly to a general lack of sufficient quantities. In addition, the combustion and handling properties of these fuels are generally unknown. The probability is high, however, that some degree of equipment modification will be necessary before these fuels can be utilized in existing equipment. The purpose of this study is to assess the capital costs of converting a variety of boiler designs and capacities to two types of coal-derived fuels; namely, lower-BTU gas (HHV = 150-700 Btu/scf) and solvent refined coal (SRC). Current activities in this area are reviewed in the following subsections. Although for many years it has been the practice of the industrial boiler sector to use waste gases (i.e., coke oven gas) of low heating values as fuels, such occurrences are too varied to be included in this discussion. The principles involved in using such fuels are, however, an integral part of the cost estimation methodology performing during this study.

2.2 CURRENT ACTIVITIES

For the most part, actions in the area of converting boilers to coal-derived fuels have been limited to studies, models, and position papers by the utility industry. This lack of actual conversion experience stems, for the most part, from a combination of the following three factors:

- Quantities of these exotic fuels are insufficient even for subscale test purposes, much less for full-scale steam generation.
- Pressure to begin such programs was absent until the energy shortage reached a severe level several years ago. This, naturally, retarded the development of the required new technology.
- The lead time required by the utility industry to implement alterations in electrical generation mode is traditionally long.

However, a discussion of germane literature as well as the current posturing by the utility industry is of interest in the context of this study.

Conversions to Lower-BTU Gas

A recent article by Henry and Burbach of Combustion Engineering, Inc., (Reference 2-1) considered the factors involved when attempting to apply low-Btu gas (130 Btu/scf) to an existing tangentially-fired boiler. The authors' major conclusions were:

- The lower heating value of the gas requires that, compared with natural gas, as much as 12 times the amount of fuel gas (by weight) be handled
- This factor may require a larger combustion volume, and either larger fuel piping or higher supply pressures.
- Operation of the on-site low-Btu gas plant may require that the steam generator be brought on line on its backup fuel (i.e., low sulfur oil) and then transferred to the low-Btu gas. This refers to the "dynamic coupling" difficulties that will be discussed later in this section.

No information on the costs associated with the required modifications were included in the paper. The article also related that Combustion Engineering currently has a four-phase contract with the Office of Coal Research to design a 200 MW pilot plant in combination with 5 ton/hr low-BTU gasification plant.

A recent paper by Frendburg (Reference 2-2) verifies much of the information in the paper by Henry and Burbach, and contains some additional elaborations:

- As the heating value of the fuel gas falls below 300 Btu/scf, the fuel pipes or ducts increase in size making it more difficult to route these pipes or ducts.
- The furnace volume of coal-fired utility boilers are inherently larger than those for either oil or gas, and will, therefore, more readily accommodate lower-Btu gas.
- Unit efficiency may decrease when firing lower-Btu gas, due to increasing heat loss to the stack.

Actual application of lower-Btu gas in power plants is seemingly limited at the present time to some program planning on the part of an electrical utility company in Illinois (References 2-3 and 2-4). Through contributions to the Electric Power Research Institute, the electric utility industry is supporting this development project, which is sponsored by Commonwealth Edison Company. The project's strategy will be to use a Lurgi gasifier to equip the 120 MW Powerton Station. It was determined that using low-BTU gas as a fuel supply possessed two major advantages over stack gas scrubbing:

- The low-Btu gas supply can generate a net excess of electric power by passing the product stream through an unfired expander turbine; this contrasts with the scrubber which uses from 5 to 10 percent of the generated power (Author's comment: it should be noted, however, that generation of low-Btu gas entails the loss of approximately 40 percent of the heating value of the feedstock coal. An overall power generation system energy balance will favor the use of raw coal).
- The associated gas purification process of the gasification system effects cleanup by removing hydrogen sulfide (for which technology exists), and treats less than 5 percent of the volume of gas that would be processed in a scrubbing system.

Detailed information on the present status of this project was not available.

Conversions to Solvent Refined Coal

The practical and economical feasibilities of utilizing solvent refined coal in existing fossil-fueled utility boilers have been analyzed in some depth (References 2-5, 2-6, and 2-7). SRC is a relatively clean fuel, being low in moisture, ash, and sulfur, and its heating value is fairly uniform regardless of the feedstock coal (about 16,000 Btu/lb). On the face of it,

this means that the refined product can be shipped on a Btu basis for proportionately less than raw coal. This factor suggests the location of refining plants near cheap sources of coal. In addition, the paper studies show significant pollution control cost savings through the use of SRC. However, the assumption is made that it can be substituted for either oil or coal without difficulty. As it is the purpose of the present study to evaluate such conversion costs, the validity of this assumption will be tested. Also, the cost of producing SRC must be factored in when comparing costs with stack gas scrubbing.

As is described in detail in Section 4 of this report, the physical properties of SRC are such that some controvery currently exists as to whether it is more advantageous to burn it as a liquid or solid. The original fuel may become a deciding factor.

There are currently two schools of thought on the subject or the applicability of solid SRC to coal-fired plants. One contends that the material is sufficiently similar to coal that existing storage facilities, pulverizers, and fuel handling and combustion equipment can all be used, with no modifications necessary. The opposing theory states the opposite: that solid SRC will melt unless preheat operation is discontinued and appropriate portions of the fuel preparation and handling equipment are externally cooled (References 2-8 and 2-4). As so little is known about the actual handling and combustion properties of this material, considerations from both cases have to be treated. The first would require essentially no cost, while some finite cost will be associated with the second.

It is generally agreed that firing liquid SRC in either oil- or coal-fired plants will require some degree of adaptation. SRC's viscosity increases dramatically below about 500F, which will necessitate, among other factors, external pipe- and vessel-heating apparatus. The extent and cost of the liquid SRC handling system will depend to some degree on the location of the SRC plant with respect to the steam generator. If the plant is located inconveniently far from the site of use, the SRC can be transported as a solid (molded pellets) to the boiler and subsequently melted. If the SRC plant is adjacent to the boiler, cooling the material to solid form will not be necessary before combustion. In either case, the usual liquid fuel handling equipment (piping, valves, pumps, storage tanks, etc.) will be required in addition to the special fuel warming equipment. Such considerations will be treated at greater length in Section 6 of this report.

Actual experience in converting steam raising boilers to the use of SRC has been, at present, restricted to preliminary program planning by some electric utility/oil company consortia in the Midwest and Southeast. In Ohio, the team of Old Ben Coal Company, Standard Oil of Ohio, and Toledo Edison are gearing up for a pilot program in which SOHIO will supply SRC, made from coal supplied by Old Ben, to an Edison generating station. Conversations with the principals involved netted the following (References 2-9, 2-10, and 2-11):

- SRC will be transported like coal in existing hopper cars.
- Heated pulverizers cannot be used; Toledo Edison's operates at about 130F.
- What effect SRC's lower ash content will have on the plant's existing ash collection method is unknown.
- Amount of possible boiler derating is unknown.
- SRC may not be able to be heated to a liquid state and stored for long periods of time; in any case, the heating must be done under pressure and an inert atmosphere, to avoid repolymerization.
- The major advantage of SRC as a substitute fuel over lower-Btu gas is the lessening of "dynamic-coupling" difficulties; i.e., a utility plant's output can vary by as much as $\pm$ 5 percent per minute, while a gasification plant's rapid turndown capabilities are far less. SRC can be stored easily and its input rate can be modulated readily.

A detailed description of the SOHIO/Toledo Edison/Old Ben enterprise has not yet been published or otherwise made available to the general public.

Additional activity in the area of SRC utilization in power plants is currently taking place at Wilsonville, Alabama. A 6 ton/day SRC pilot plant, sponsored jointly by The Southern Company system and the Electric Power Research Institute, was completed at this location in August, 1973. Preliminary plans are being made for applying the SRC obtained from this pilot plant to a Southern Services generating plant (Reference 2-12).

2.3 SUMMARY AND CONCLUSIONS

The motivation for fuel substitution in steam-raising boilers is based on fuel availability and/or pollution control. The continuing shortage of clean substitute fuels will cause reliance on alternate fossil fuels. With the advent of coal-derived fuels, most of which require special handling and

combustion procedures, some effort will have to be expended to convert conventional combustion systems to their use. Of the various coal conversion processes, the products from two of them are considered in this study: solvent refined coal and synthesis gas.

Thus far, activities aimed at converting full-scale utility boilers to the use of either of these types of fuels has been limited to studies, position papers, and preliminary program planning by a few electric utility/oil company consortia in the Southeast and Midwest. For the gaseous coal-derived fuels, a Lurgi coal gasifier will be used to supply a 120 MW generating station. Details on the present status of this project were not available.

In another program, solid SRC will be utilized in a coal-fired power plant. It is anticipated by the participants that little or no equipment conversion will be necessary. An additional SRC-related project is underway in the Southeast, where SRC from a 6 tons of coal/day pilot plant will be supplied to an existing generating unit.

A major advantage of solid SRC over lower-Btu gas as a boiler fuel is that, in contrast to the product from an in situ gasifier, SRC can be stored when not in demand by the power plant, thus removing the "dynamic coupling" difficulties prevalent in the gasifier/steam plant strategy.

There is as yet no widespread move to employ either gasified coal or SRC in the industrial boiler sector.

The absence of cost data based on actual experiences in converting to these exotic fuels necessitates that such costs be estimated for this study. The estimation procedure, performed by personnel of The Coen Co., was based on a knowledge of the fuel's physical properties as well as an extensive background of boiler conversions to similar fuels. Section 6 of this report discusses the estimation methods and assumptions used in deriving the cost figures.

SECTION 3

CHARACTERIZATION OF COMBUSTION EQUIPMENT

3.1 INTRODUCTION

The previous section of this report reviewed current activities involving the substitution of various coal-derived fuels for conventional fossil fuels in stationary combustion equipment. The majority of such activity currently centers around full-size utility boilers, with less apparent effort being expended in the industrial boiler sector. Both sectors are, however, obvious candidates for the application of fuel switching as a SO_x abatement strategy.

The choice of the combustion equipment types and their capacities ultimately considered in this study was based on two factors:

- Determination of the most prolific stationary SO_x sources. According to the 1970 nationwide emission estimates given in Reference 3-1, fuel combustion in stationary sources accounts for 79 percent of the total controllable SO_x emissions. Of that amount, 73 percent is contributed by steam-electric, 18 percent by industrial, 3 percent by commercial and institutional, and 5 percent by residential sources. It appeared that the greatest benefit would be derived from considering only the first two source categories.
- Possible impact on the ambient air quality in the immediate vicinity of the source. This consideration demanded the inclusion of the smaller SO_x sources.

These criteria acted to establish the framework for the determination of the types and capacities of combustion equipment to be considered in this report; namely, steam-raising boilers in the 10^7 to 1000 x 10^7 Btu/hr (1-1000 MW) capacity range, which encompasses all industrial and utility size equipment. Including a wide variety of boilers and capacity ranges increases the probability of arriving at a global relationship between equipment conversion capital cost and capacity.

Boilers used for industrial purposes in the capacity range of interest include the following general types:

- Firetube (packaged)
- Watertube (packaged or field-erected)
- Stoker (field-erected)

Utility boiler types, all of which are field-erected, are categorized mainly by fuel firing mode. These include:

- Face-fired
- Tangentially-fired
- Turbo-fired
- Cyclone-fired

The remainder of this section is devoted to brief descriptions of these types of industrial and utility boilers. Throughout the discussion, it should be noted that the term "packaged" refers to a shop-fabricated boiler which is shipped as a complete unit to the point of use. This fact naturally places an upper limit on physical size; the largest packaged boilers can be transported by barge, and most are sized for railroad flat cars. The opposite fabrication method is described by the term "field erected," meaning the boiler is assembled from its component parts at the site of eventual operation.

Additional, more detailed specifications on the design, construction, and operation of these boilers can be obtained from the references cited.

3.2 INDUSTRIAL BOILER TYPES

3.2.1 Firetube Boilers

Firetube boilers (all of which are packaged) are used where steam demands are relatively small, usually for heating systems, industrial process steam, or as portable boilers. In this design, the hot combustion gases are passed through tubes submerged in a water-containing vessel. The principal types of firetube boilers include Horizontal Return Tubular (HRT), Scotch Marine, and "Short Firebox," the capacities of which fall in the 10^7 to 25 x 10^6 Btu/hr range.

These three types of boilers will be lumped together under the firetube boiler category, mainly because of similarities in capacities and firing equipment. HRT boilers are not commonly built for industry at present, being more predominant 15 to 20 years ago. The same is true of the short firebox boiler. The Scotch Marine boiler type refers to firetube boilers in general

use today for low pressure (15 to 20 psig) saturated steam applications with steam flow capacities in the 300 to 25,000 lb/hr range. Firetube boilers are fired solely on gaseous or liquid fossil fuels. Typical manufacturers are Cleaver Brooks, Superior, and Bryant (References 3-2, 3-3).

3.2.2 Watertube Boilers

This category includes both field-erected as well as packaged units. Common sizes for the former type fall between 50×10^6 and 500×10^6 Btu/hr, while 10^7 to 250×10^6 is the capacity range for the latter. Larger packaged boilers, above 450×10^6 Btu/hr, are currently being designed and supplied, but are not yet common.

As the name implies, watertube boilers are designed to flow water through the heat transfer tubes, instead of combustion products as in the firetube design. Because of the smaller diameter pressurized components and the advantage using tubes gives in accommodating expansion, they are better able to contain the pressure and afford an inherently safer design.

Field-erected boilers are usually balanced draft and therefore require both forced draft and induced draft fans. Field-erected boilers are commonly fired with coal, gas and/or oil. Many such boilers exist today but very few new applications have capacities lower than 200×10^6 Btu/hr, except for pulverized or stoker coal-fired units. This is because of the packaged boiler's domination of the oil- and gas-fired boiler market, which is in turn due to their low capital cost in the sizes between 12×10^6 and 200×10^6 Btu/hr.

Packaged watertube boilers are used for gas and oil firing applications. They are not used for coal firing because they have much smaller furnace volumes than are permissible. They are designed to be rail-shipped as a complete, single package with minimum fieldwork. The furnaces are also designed to operate under positive pressure versus the balanced or slightly negative pressure found in coal-fired boilers.

Both types of boilers use similar type firing equipment. The register-type burner is generally used, with burner capacities being between 50×10^6 and 120×10^6 Btu/hr on a field-erected boiler, and up to 350×10^6 Btu/hr on a packaged boiler. Packaged boilers generally have one burner although older units were fitted with multiple burners - usually two. Popular types of industrial watertube boilers, both packaged and field-erected, are manufactured by Combustion Engineering Company, Riley Stoker, and Erie City Company (References 3-2, 3-4, 3-5, 3-6).

3.2.3 Stoker-Fired Boilers

The two major options available for the controlled combustion of coal are suspended firing, in which the fuel is pulverized to a fine dust prior to being combusted in a wall-mounted burner, and bed combustion, which causes oxidation to take place in and above a layer of raw coal. An example of the latter method is found in the traditional hand-fired coal furnace. Mechanical stoker-fired boilers are an improvement over this design.

The general stoker-fired boiler category includes spreader, underfeed, vibrating grate, chain grate, and traveling grate stokers. All terms refer to the method of coal/air introduction and mixing, as well as char and ash removal. Firing capacities generally range from 15×10^6 to 250×10^6 Btu/hr. It is very unusual for a stoker to be designed with less than 20×10^6 Btu/hr capacity. Units above 200×10^6 Btu/hr are also rare.

Stokers are often preferred over pulverized-fired units because of their ability to burn a wide variety of coals and other solid fuels, greater operating range, and lower power requirements.

A major impact on the cost of converting mechanical stoker-fired boilers to a substitute, cleaner fuel will be the required modification of the equipment inside the furnace volume. Pulverized coal-fired units of the same capacity incur no such costs. This effect will be noted in Section 6, later in this report.

3.3 UTILITY BOILERS

Most of the nation's combustion-derived electricity is generated in large fossil-fueled central stations, which consist of watertube boilers operating in the supercritical pressure region serving turbine-generators in the million kilowatt range. Firing capacities of individual burners in utility boilers commonly range up to as high as 125×10^6 Btu/hr. One-thousand MW wall-fired units may require as many as sixty separate burners.

Although there are some differences among utility boiler designs in such factors as furnace volume, operating pressure, and configuration of internal heat transfer surface, the principle distinction is firing mode. This includes the type of firing equipment, the fuel handling system, and the placement of the burners on the furnace walls. The major firing modes, of which equipment conversion costs are a function, are briefly described below.

3.3.1 Wall-Fired Boilers

The multiple burners in wall-fired utility boilers are usually mounted in geometrical patterns on the vertical furnace wall, although some designs employ roof-mounted burners. Depending on the manufacturer and firing capacity, the burners in vertical wall-fired boilers may be mounted either on a single wall or on opposite walls. Figure 3-1 shows cross-sections of these two types of boilers. Vertical-wall burners are usually of the register type, while "intertube" burners are normally used in roof-mounted applications. In any case, the burners are fired in a fixed direction normal to the wall. This is in contrast with the tangential firing method which allows some degree of burner "tilt."

Individual burner firing rates lie in the 75×10^6 to 125×10^6 Btu/hr range; the total heat release rate of wall-fired boilers normally falls between 500×10^6 and $10{,}000 \times 10^6$ Btu/hr, which corresponds to a generating capacity range of 50 to 1000 MW.

The wall-fired boiler design is capable of utilizing all conventional fossil fuels, including natural gas, fuel oil, and pulverized coal. Well-known manufacturers of this type of boiler include The Babcock and Wilcox and Foster Wheeler Companies (Reference 3-7).

3.3.2 Tangentially- and Turbo-Fired Boilers

Tangentially- and turbo-fired boilers are grouped together because the burner equipment is essentially identical for both boiler types; i.e., both use multiple burners, both fire between the boiler tubes, fuel/air mixing takes place within the boiler furnace itself (as opposed to the burner throat of a register type burner), and they employ a common burner capacity range - 75×10^6 to 125×10^6 Btu/hr.

The boilers are physically quite different. Tangential boilers, as shown in Figure 3-2, are fired with groups of 4 burners at the same elevation with each burner located in a corner of the boiler. Each burner fires along the tangent of a small imaginary circle in the center of the boiler. The resulting spin of the four "flames" creates high turbulence and thorough mixing of fuel and air in the center of the furnace. Additional levels of burners at 6- to 10-foot increments provide additional capacity for larger boilers.

Turbo-fired furnaces, as illustrated in Figure 3-3, provide a similar turbulent mixing of fuel and air in the furnace, but in this case, the burners are mounted in opposing walls of a "bottle neck" type furnace. The walls are tilted towards each other such that opposing burners fire down at a 30° angle towards the center of the lower part of the boiler. The burner sizes mentioned

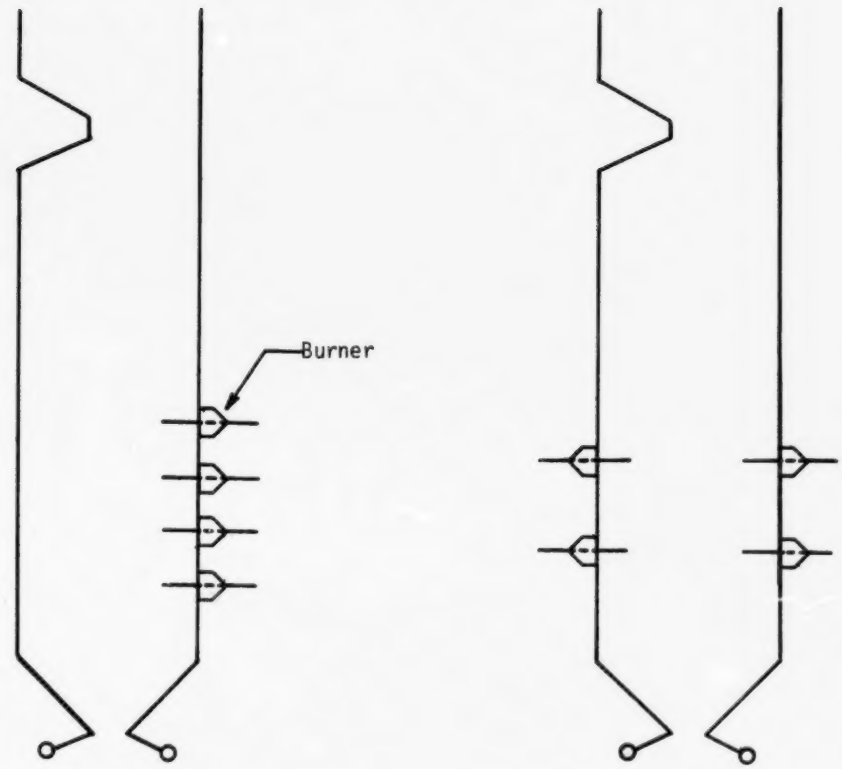

Figure 3-1. Vertical wall-fired utility boiler shapes and burner configurations

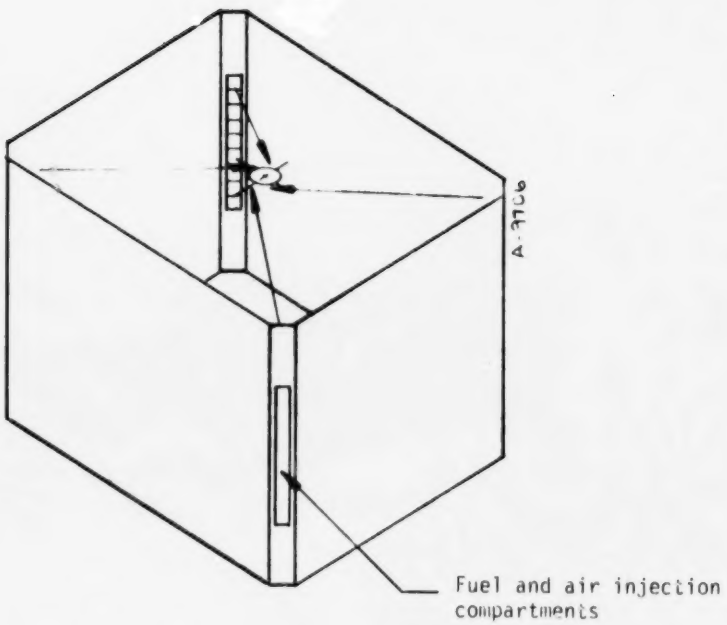

Figure 3-2. Tangentially-fired utility boiler shape and firing pattern

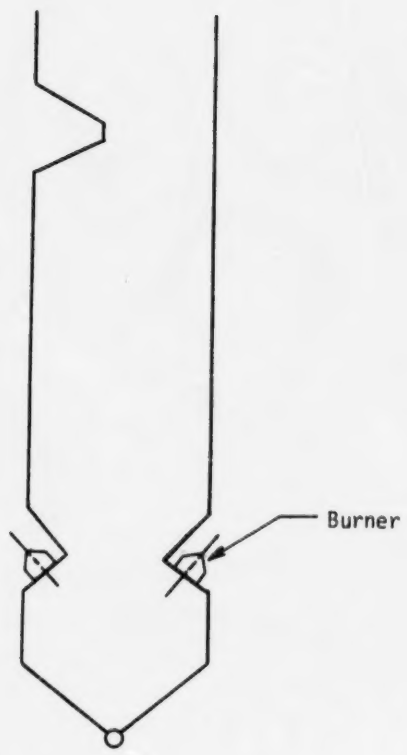

Figure 3-3. Riley Turbo® furnace shape and burner configuration

above are the same as those commonly found in tangentially-fired boilers. Therefore, higher boiler capacities are attained by increasing the boiler width and the number of burners.

Turbo-fired boilers are manufactured by Riley Stoker, while most of the tangentially-fired utility boilers are constructed by Combustion Engineering, Incorporated (Reference 3-8).

3.3.3 Cyclone-Fired Boilers

A cyclone boiler is composed of the combination of a watertube boiler and a separate "cyclone" furnace (or series of furnaces) that are themselves water-cooled. Cyclone furnace firing arrangements are depicted in Figure 3-4. This type of furnace is capable of handling coals with high slag viscosities (250 poise at 2600F or lower). The air-conveyed coal and secondary air are injected into the furnace such that a highly swirling "cyclone" flame results. The high heat release of the furnace results in the high gas temperatures that are necessary for the formation of liquid slag. Slag taps permit continuous removal of the molten slag. Typical single furnaces are designed for firing capacities between 100×10^6 and 400×10^6 Btu/hr, with multiple cyclone furnaces being employed for loads above 400×10^6 Btu/hr. Cyclone furnaces are designed primarily for coal-firing, with gas or oil available only for standby operation. For gas operation, the fuel is injected horizontally with the secondary air.

Most cyclone-type boilers are constructed by The Babcock and Wilcox Company or its subsidiaries (Reference 3-7).

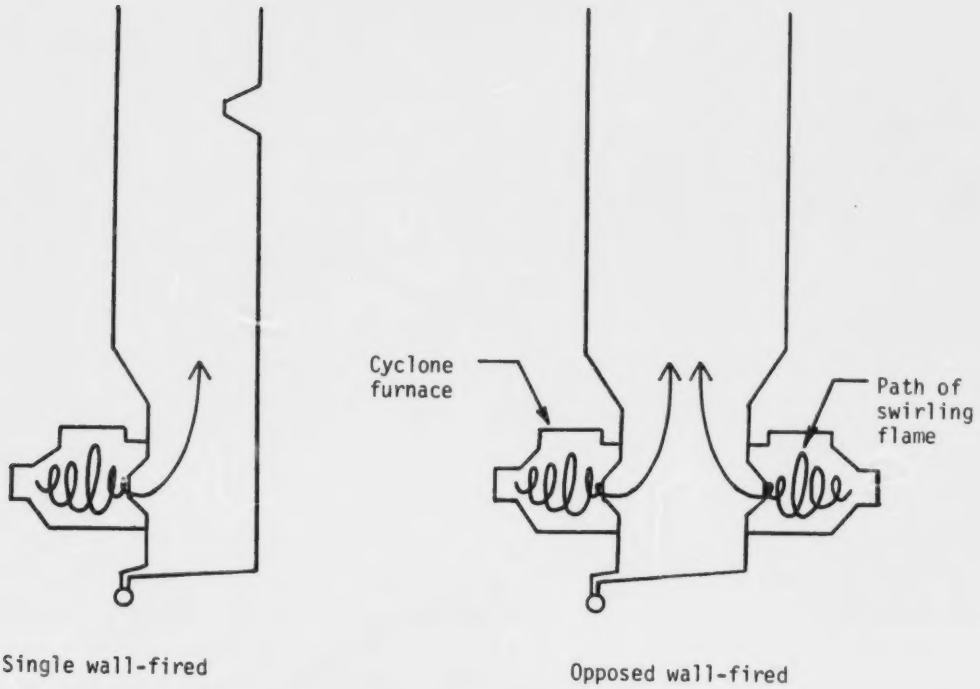

Figure 3-4. Cyclone furnace firing arrangements

SECTION 4

CHARACTERIZATION OF SUBSTITUTE FUELS

4.1 INTRODUCTION

The preceding section provided brief descriptions of the types of SO_x emitting combustion systems for which the costs of switching from conventional fossil fuels to various coal-derived fuels were estimated in this study. The present section attempts to characterize these exotic fuels.

Four distinct coal conversion routes are possible. These include: pyrolysis, hydrogenation, solvation, and production of synthesis gas. The amount, type and quality of the products from each of these methods depend upon the coal properties and process conditions (Reference 4-1).

In pyrolysis, the coal is heated in an inert atmosphere to break it down into solids, liquids, and gases, the amounts of which are proportional to the heating rate.

In hydrogenation reactions, coal and hydrogen are reacted together directly. In the presence of a catalyst at 850F and at elevated pressures, a liquid product is made. If a catalyst is not present, the coal reacts directly with hydrogen at higher temperatures (about 1600F) and pressures (150-300 psi) to form methane.

During solvation, the coal is dissolved and, with the addition of hydrogen at modest pressure, can be filtered and converted into an essentially ash-free and low sulfur solid or liquid.

Synthesis gas is produced by reacting coal with an oxidizing agent and steam. The resulting low heating value gas can then be used to make a high-Btu gas by a methanation step which reacts the purified gas over a nickel catalyst.

The present study concerns itself with the conversion of steam-raising boilers firing conventional fossil fuels to the use of selected products from solvation and synthesis gas coal conversion methods; namely, solvent refined coal (SRC) and lower-Btu gas. Brief summaries of these processes and their products are presented in the following subsections.

4.2 LOW- AND MEDIUM-BTU GAS

The basic process for converting solid coal to a fuel gas comprising principally nitrogen, carbon monoxide, hydrogen, and a certain amount of methane is well understood. In fact, the "town gas" commonly used, especially in Europe, before the general availability of natural gas was produced with earlier versions of present-day equipment. In general, these gases are produced when an insufficient quantity of oxidizer is supplied to the coal at a high temperature, thus preventing the reaction from going to completion to form carbon dioxide and water.

Most gasification processes have in common four basic sequentially-occurring reactions. The principal heat-producing reaction is oxidation, which results when oxygen reacts with fuel to form water and carbon dioxide:

$$C + O_2 \rightarrow CO_2$$

$$H_2 + 1/2\ O_2 \rightarrow H_2O$$

Next comes the gasification reaction, which is the most endothermic. This reaction occurs when unburned carbon from the fuel reacts with steam and carbon dioxide to form hydrogen and carbon monoxide:

$$C + \begin{pmatrix} H_2O \\ CO_2 \end{pmatrix} \rightarrow CO + \begin{pmatrix} H_2 \\ CO \end{pmatrix}$$

The third reaction, hydrogasification, is mildly exothermic and takes place when hydrogen reacts with fuel carbon to give methane:

$$C + 2H_2 \rightarrow CH_4$$

Finally, and sometimes concurrently with the preceding reactions, devolatilization occurs when the fuel is subjected to heating:

$$\text{Coal} + \text{Heat} \rightarrow C + CH_4 + HC$$

Among the myriad types of gasification processes either operating or contemplated, these four basic reactions can occur simultaneously in a reactor, or each may take place in a particular region of the reactor, or each may be confined to a separate vessel. Most of these processes are designed so that

the heat required by the highly endothermic gasification reaction is supplied by the heat released from the other three reactions. Adjusting the amount of oxidizer lent to the process controls this heat balance. Raw gas leaving the gasifier consists mainly of methane, hydrogen, nitrogen, carbon oxides, and sulfur compounds. The sulfur compounds and other impurities are removed downstream.

The basic gasification process described to this point delivers a product gas whose heating value abides primarily in the carbon monoxide and hydrogen resulting from the gasification step. This product is usually termed "lower-Btu gas." This definition is employed because there are two fuel-gas heating values of potential interest below the SNG level of 900 to 1000 Btu/scf. The first of these is the range of 300 to 700 Btu/scf, which is referred to as medium-Btu gas. The other is the range of 150 to 250 Btu/scf, which is referred to as low-Btu gas.

Two basic motives exist for converting coal to gas, depending on the ultimate application (Reference 4-2):

- If pipeline quality, high-Btu gas is desired, the product gas must go through an additional methanation step. This is an expensive process, whereby additional hydrogen is produced and chemically reacted with carbon monoxide to form methane. Current SNG costs are in the range of \$1.05 - \$1.50/10^6 Btu.
- If the purpose of gasifying coal is solely to remove ash and sulfur so that the fuel gas is nonpolluting when burned, the heating value need only be high enough to maintain a stable flame, with a minimum deleterious effect on plant efficiency. Medium- and low-Btu gases are well suited for this purpose. In most processes, oxygen injected into the gasification step will produce the former gas ("oxygen-blown"), while air injection will produce low-Btu gas ("air-blown"). Medium-Btu gasification saves 10 to 15 percent in coal feed rate, 30 to 35 percent of plant investment, and 25 to 35 cents/10^6 Btu relative to SNG. Producing low-Btu gas provides an additional savings of 5 to 10 cents/Btu over gases of intermediate-Btu heat content.

The attractiveness of lower-Btu gas as a boiler fuel is quite apparent. Studies have shown that the most feasible location for lower-Btu gasification plants is at the point of use, while the product from SNG plants can be economically transported by pipeline over long distances (References 4-3, 4-4, 4-5, 4-21). It is therefore easy to visualize lower-Btu gasification plants

constructed next to a new or existing combustion system, whether the product is destined for the steam-electric utility or industrial boiler sector.

Combustion systems firing conventional fossil fuels, however, will require some degree of equipment modification before these new gaseous fuels can be burned. Assessing the costs of such conversions was the objective of the present study.

For the purposes of the study, certain simplifying assumptions are made about the combustion characteristics of these gases. Table 4-1 shows the chemical compositions of selected lower-Btu gasified coal fuels. These gases are representative of the products of all gasification processes, detailed descriptions of which are given in Appendices A and B. The heating value of the gases range from 170 Btu/scf for the air-blown Lurgi to 780 Btu/scf for the Hydrane process. For the most part, heating value is directly proportional to volume percent of methane.

It will be assumed that the combustion characteristics of these and all lower-Btu gases will depend on heating value alone and be decoupled from specific chemical composition. This will allow the range of gas types to be treated as a continuum. In this way, the equipment conversion costs of substituting for these gases can be related to heating value. Section 6 will describe in more detail the method used for incorporating a heating value term in the conversion cost equations for the gaseous substitute fuels.

4.3 SOLVENT REFINED COAL

In Section 4.2, the feasibility of using coal-derived gases of lower heating values (<1000 Btu/scf) as low sulfur boiler fuels was discussed. Similar advantage can be gained by using the products from coal conversion processes that generate clean fuels that are liquids or solids at room temperature. Examples of the former type are the products from the Bergius - I.G. Farben, Fischer-Tropsch, COED, H-Coal, and Flash Pyrolysis processes. Ample descriptions of these treatment methods, which are essentially pyrolysis or hydrogenation processes, appear in References 4-14, 4-15, and 4-1. Clean solid fuels from solvation processes are exemplified by solvent refined coal (SRC). Cost estimations for converting stationary combustion equipment to the use of this fuel were established in the present study.

Solvent refined coal (SRC) is a name given to a reconstituted coal which has been dissolved, filtered, and separated from its solvent. It is moisture-free, low in sulfur and ash, and can apparently be handled in the liquid as

TABLE 4-1

COMPOSITIONS OF SELECTED LOW- AND MEDIUM-BTU GASIFIED COAL FUELS

("-" denotes negligible quantity and "m" denotes missing data)

Item		Koppers-Totzek (4-6)	Koppers-Totzek (4-6)	Koppers-Totzek (4-6)	Synthane (4-7)	BCR, Inc. (4-8)	IGT (4-9)	Oxygen Lurgi (4-10)	Hydrane (4-11)	Wellman-Galusha (4-12)	Commercial Lurgi (4-10)	Texaco (4-13)
Coal Type		Western	Illinois	Eastern	Pgh. Seam	W. Ky.	Lignite	Sub. Bit.	Pgh. Seam	m	m	m
Product Gas, Volume %	CO	58.68	55.38	55.9	16.8	44.0	19.5	17.1	4.2	27.0	14.1	27.5
	CO_2	7.04	7.04	7.18	28.8	14.0	24.6	31.4	1.3	2.1	12.5	1.0
	H_2	32.86	34.62	35.39	27.8	24.4	24.5	40.2	21.4	14.4	20.9	25.3
	N_2	1.12	1.01	1.14	0.8	0.6	0.6	-	1.0	47.25	40.0	37.2
	H_2S	0.28	1.83	0.35	0.5	1.4	0.4	0.3	3.3	0.05	0.1	0.009
	COS	0.02	0.12	0.04	-	-	-	-	-	-	-	-
	CH_4	-	-	-	24.5	15.6	28.2	10.2	68.5	2.6	5.8	0.5
	C_mH_n	m	m	-	0.8	-	2.1	0.4	m	-	-	-
	H_2O	-	-	-	-	-	m	-	-	6.6	6.6	8.5
S(gm/10^6Btu)		-	-	-	-	-	-	-	-	117	221	-
HHV(Btu/scf)		295	290	294	406	380	467	400	780	160.4	172.7	175.8

well as the solid state. In the latter form, it is brittle and easily grindable. The process of pulverization can, however, heat the material sufficiently to cause undesirable agglomeration. Its major advantage is that its heating value remains at 16,000 Btu/lb regardless of the quality of the coal feedstock.

The SRC process has been under development for a number of years. Pittsburg & Midway Coal Mining Company, under the sponsorship of the Office of Coal Research, demonstrated the technical feasibility of the process on a pilot scale in 1964. In 1972, construction was begun on two additional SRC pilot plants. The 6 ton/day Wilsonville, Alabama, facility has been completed and is currently producing small amounts of material for experimental purposes. The project is sponsored by the Electric Power Research Institute and Southern Services. A larger plant, 50 ton/day, is located at Tacoma, Washington, and will be completed in late 1974. In both facilities, emphasis is placed on developing a utility fuel of a quality that will meet environmental standards when burned (Reference 4-3).

The solvent refined coal process is shown schematically in Figure 4-1. SRC is produced by first dissolving coal under pressure in a recycled solvent containing a small quantity of hydrogen. The coal solution is then filtered to remove virtually all of the mineral matter including the pyritic sulfur. Small quantities of hydrocarbon gases and lighter liquids are distilled off. The main product from the process is a heavy organic material which has a melting point of about 350F and, depending on the composition of the feedstock coal, contains less than 0.1 percent ash and less than 0.8 percent sulfur. The yield of solvent refined coal and other liquid products is approximately 90 percent of the original coal (References 4-16, 4-17).

The compositions of typical samples of SRC are presented in Table 4-3, while the analysis of the coal from which they were derived is shown in Table 4-2. These analyses are associated with projects performed by the Bureau of Mines (Reference 4-18), Combustion Engineering, Inc. (Reference 4-19), and The Babcock and Wilcox Company (Reference 4-20), in an effort to determine the combustion characteristics of SRC, samples of which were supplied by the Office of Coal Research. The investigators came to the following general conclusions:

- Based on both the proximate and ultimate analyses, the solid phase material appeared similar to a high volatile bituminous coal except for the reduced sulfur and ash content.
- Thermogravimetric analyses indicate ignition characteristics similar to a high volatile bituminous coal, but for burnout it appears to more closely resemble a semianthracite.

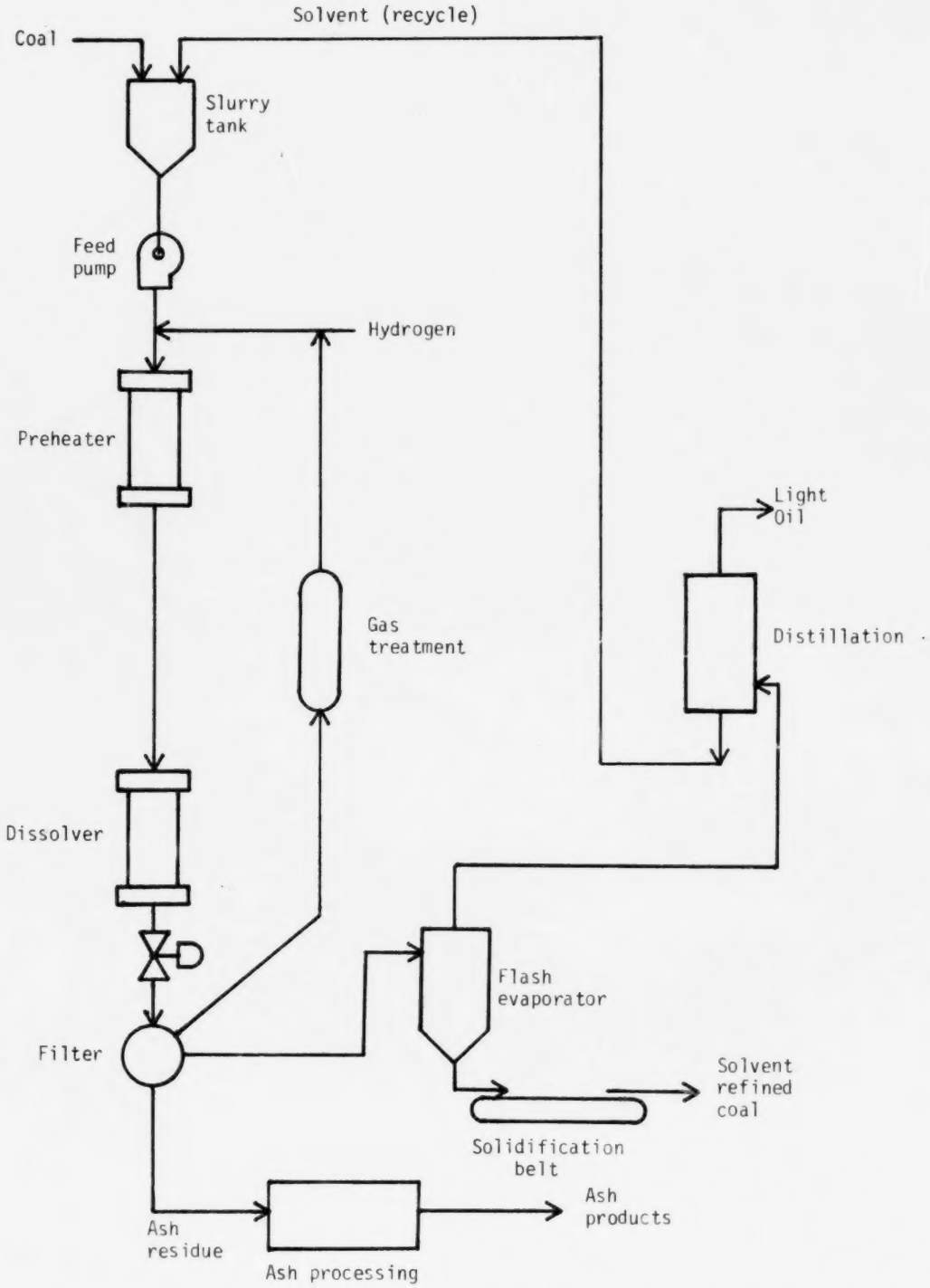

Figure 4-1. Solvent Refined Coal Process (Reference 4-16)

TABLE 4-2

ANALYSIS OF KENTUCKY NO. 11 COAL, AS RECEIVED

(References 4-18, 4-19)

Proximate Analysis, Mass %	
Total	5.2
Volatile Matter	40.2
Fixed Carbon	48.1
Ash	6.2
Ultimate Analysis, Mass %	
Hydrogen	5.5
Carbon	70.9
Nitrogen	1.9
Oxygen	12.0
Sulfur	3.5
Ash	6.2
Heating Value, Btu/lb	12,770
Hardgrove Grindability	61

TABLE 4-3

ANALYSIS OF SOLVENT REFINED COAL

("m" denotes missing data)

Proximate Analysis, Mass %	Ref. 4-18	Ref. 4-19	Ref. 4-20
Total Moisture	0.0	0.0	0.0
Volatile Matter	57.6	59.2	57.7
Fixed Carbon	42.3	40.6	40.9
Ash	0.1	0.15	0.36
Sulfur	m	m	1.1
Ultimate Analysis, Mass %			
Moisture	0.0	0.0	0.0
Hydrogen	5.5	5.3	5.2
Carbon	88.2	86.9	88.4
Nitrogen	1.5	1.4	1.44
Sulfur	1.1	1.4	1.1
Oxygen	3.6	4.8	3.5
Ash	0.1	0.15	0.36
High Heating Value, Btu/lb	15,680	15,559	15,730
Hardgrove Grindability	m	m	164
Melting Temperature, F	m	300	m
Pumping Temperature, F	m	m	500
Atomization Temperature, F	m	m	665

- The grindability index (about 160) indicated that the solid SRC can be pulverized with less power than nonprocessed coal (e.g., grindability for the Kentucky No. 11 coal was 61).
- In pulverized form, firing tests indicated that the material tended to agglomerate in the fuel lines when the primary (coal conveying) air was preheated.
- In the liquid phase, firing tests indicated that the material was similar to No. 6 fuel oil in handling and combustion characteristics. The preheating requirements are greater, however. For good pumpability (viscosity <30 cp) it must be heated above 635F. Because of the expulsion of volatile matter at temperatures above 350F, heating should be carried out under pressure in a closed system.
- When firing in the liquid phase, all fuel handling equipment in contact with the SRC must be heated to above 350F. In addition, steam-atomizing, heavy oil guns are recommended to eliminate the need for heating the gun components with an external heat source.

As implied by these conclusions, there remains some question as to the most advantageous phase in which to handle and burn the SRC. If applied in the solid form to conventional pulverized coal-fired combustion equipment, the retrofit procedure may be straightforward and inexpensive if most of the original equipment can be used and if the fuel handling equipment need not be externally cooled. When heated, by all indications, this material can be fired as an oil. In both cases, however, unforeseen retrofit difficulties may arise. More light will be cast on the situation when the results of additional EPRI-funded combustion tests, currently being performed by Combustion Engineering and Babcock & Wilcox, become available early in 1975.

As was related in Section 2 of the present study, no actual conversions of conventional steam-raising boilers of any capacity to the use of solvent refined coal have yet taken place. This is partially due to a general lack of sufficient quantities of this fuel at the present time. For the purposes of this study, the conversion cost estimation methods described in Section 5 will necessarily be based on past conversion experience involving similar substitute fuels.

4.4 SUMMARY AND CONCLUSIONS

Of the four basic coal conversion routes, pyrolysis, hydrogenation, solvation, and synthesis gas formation, representative products from the latter two processes have been considered in this study.

Solvent refined coal, in its solid state, is brittle and readily grindable into a fine powder. It is low in ash and sulfur, moisture free, and can be melted and handled as a fluid. Its heating value is about 16,000 Btu/lb, regardless (theoretically) of the type of feedstock coal. If its application as a boiler fuel is proven feasible, the major advantages afforded by SRC are:

- Use of plentiful high-sulfur coal reserves would be permitted
- The uniformity of the SRC product would permit power plants to use one "off-the-shelf" boiler design

The production of synthesis gas from coal has a lengthy history, and the technology is currently being revived. Most coal gasification processes have in common four basic reaction steps, ultimately producing a gas of heating value below that of natural gas (150-700 Btu/scf). To produce synthetic natural gas (SNG), the products from most of the gasification processes can be exposed to additional methanation steps. Economics demand that lower-Btu gasification plants be located on the site of use, while it is feasible to pipe SNG over long distances. As lower-Btu gas is less expensive than SNG to produce, is sulfur and ash free, and by all indications is able to produce a stable, trouble-free flame, it shows promise as a boiler fuel.

In order to use either lower-Btu gas or SRC in existing stationary boilers, it will be necessary to convert the combustion equipment from the use of conventional fossil fuels. As this has yet to occur on a large scale for any of these exotic fuels, the conversion costs appearing in this report are necessarily estimations, based on past conversion experience to similar substitute fuels.

SECTION 5

SELECTION OF FUEL SUBSTITUTION OPTIONS

Section 3 of this report described the types of combustion equipment that will be considered as candidates for conversion to cleaner fuels. These consist of all major types of industrial and utility boilers, encompassing a boiler capacity range from 10^7 Btu/hr to 1000 x 10^7 Btu/hr. For an estimated 35% thermal efficiency, these heat release rates correspond to an electric generating capacity range of 1 to 1000 MW. Section 4 of this report discussed the various types of clean fuels considered as subsitutes for conventional, high sulfur fossil fuels. These included solvent refined coal, low-Btu gas, medium-Btu gas, and natural gas. The first three are of interest in that they are the products of promising coal-conversion processes. The costs of equipment conversions to natural gas, an operation for which ample experience has already been gained, will act as a reference point for the conversions to the other fuels.

The information contained in Sections 3 and 4 helped to define the logical fuel substitution options available for a given type of boiler firing a given type of original fuel. These options are compiled in Table 5-1. The major points to be gained from this table are the following:

- The initial assumption is that all boiler types are capable of being converted to all of the substituted fuels.
- This number is reduced by the exclusion of certain illogical conversions, based on the following reasons:
  - Nonexistence of coal-fired firetube and packaged watertube boilers
  - Exorbitant cost associated with converting oil-fired combustion equipment to solid SRC (only conversions from solids to liquids or gases, and from liquids to gases are judged practical)
  - Nonexistence of oil-fired stoker and cyclone furnaces

TABLE 5-1

FUEL SUBSTITUTION OPTIONS

Original Fuel	Boiler Category	Applicable Substitute Fuels	Comments
Coal	Industrial Types:		
	• Firetube	None	No coal-fired boilers of this type
	• Packaged watertube	None	Essentially no coal-fired boilers of this type
	• Field-erected watertube	LBG, MBG, NG LSRC, SSRC	
	• Stoker	LBG, MBG, NG LSRC, SSRC	Equipment conversion will necessitate modification of equipment internal to the boiler; solid SRC cannot be burned like coal (on the grates) due to its low melting point.
	Utility Types:		
	• Cyclone-fired	LBG, MBG, NG LSRC, SSRC	
	• Tangentially-fired	LBG, MBG, NG, LSRC, SSRC	
	• Wall-fired	LBG, MBG, NG LSRC, SSRC	
	• Turbo-fired	LBG, MBG, NG LSRC, SSRC	
Oil	Industrial Types:		
	• Firetube	LBG, MBG, NG LSRC	Solid SRC is considered an illogical substitute fuel for boilers originally firing oil
	• Packaged watertube	LBG, MBG, NG LSRC	Solid SRC is considered an illogical substitute fuel for boilers originally firing oil

Notation: LBG = low-Btu gas
MBG = medium-Btu gas
NG = natural gas
LSRC = liquid SRC
SSRC = solid SRC

TABLE 5-1 (Concluded)

Original Fuel	Boiler Category	Applicable Substitute Fuels	Comments
	• Field-erected watertube	LBG, MBG, NG, LSRC	Solid SRC is considered an illogical substitute fuel for boilers originally firing oil
	• Stoker	None	Stokers are fired solely with solid fuel
	Utility Types:		
	• Cyclone-fired	None	Essentially no oil-fired cyclone furnaces; designed mainly for coal
	• Tangentially-fired	LBG, MBG, NG LSRC	Solid SRC is considered an illogical substitute fuel for boilers originally firing oil
	• Wall-fired	LBG, MBG, NG LSRC	Solid SRC is considered an illogical substitute fuel for boilers originally firing oil
	• Turbo-fired	LBG, MBG, NG, LSRC	Solid SRC is considered an illogical substitute fuel for boilers originally firing oil
Notation:	LBG = low-Btu gas MBG = medium-Btu gas NG = natural gas LSRC = liquid SRC SSRC = solid SRC		

These options were instrumental in the determination of the required equipment conversion cost data, as indicated by the space enclosed within the bold lines in Figures 5-1 and 5-2. These figures are the forms of the master data sheets that were ultimately used to tabulate the cost figures. The two extreme left-hand columns contain the delineation of industrial and utility boiler types, an indication of whether the boiler is packaged or field-erected, and its normal capacity range in units of 10^6 Btu/hr. The columns between the double vertical lines serve to space out the increments in boiler capacity range. The letters in the rows contained in the extreme right-hand column indentify the cost category entered in the row; "E" denotes equipment cost, "I" denotes installation expense, and "T" is the sum of E and I, or, total capital investment.

Five sheets of the form of Figure 5-1 will contain the costs for converting the appropriate boilers from coal to the use of the five substitute fuels. Similarly, Figure 5-2 indicates that four data sheets will be completed for conversions of oil to the four applicable substitute fuels.

The equipment conversion cost estimations and associated documentation are contained in the following section of this report.

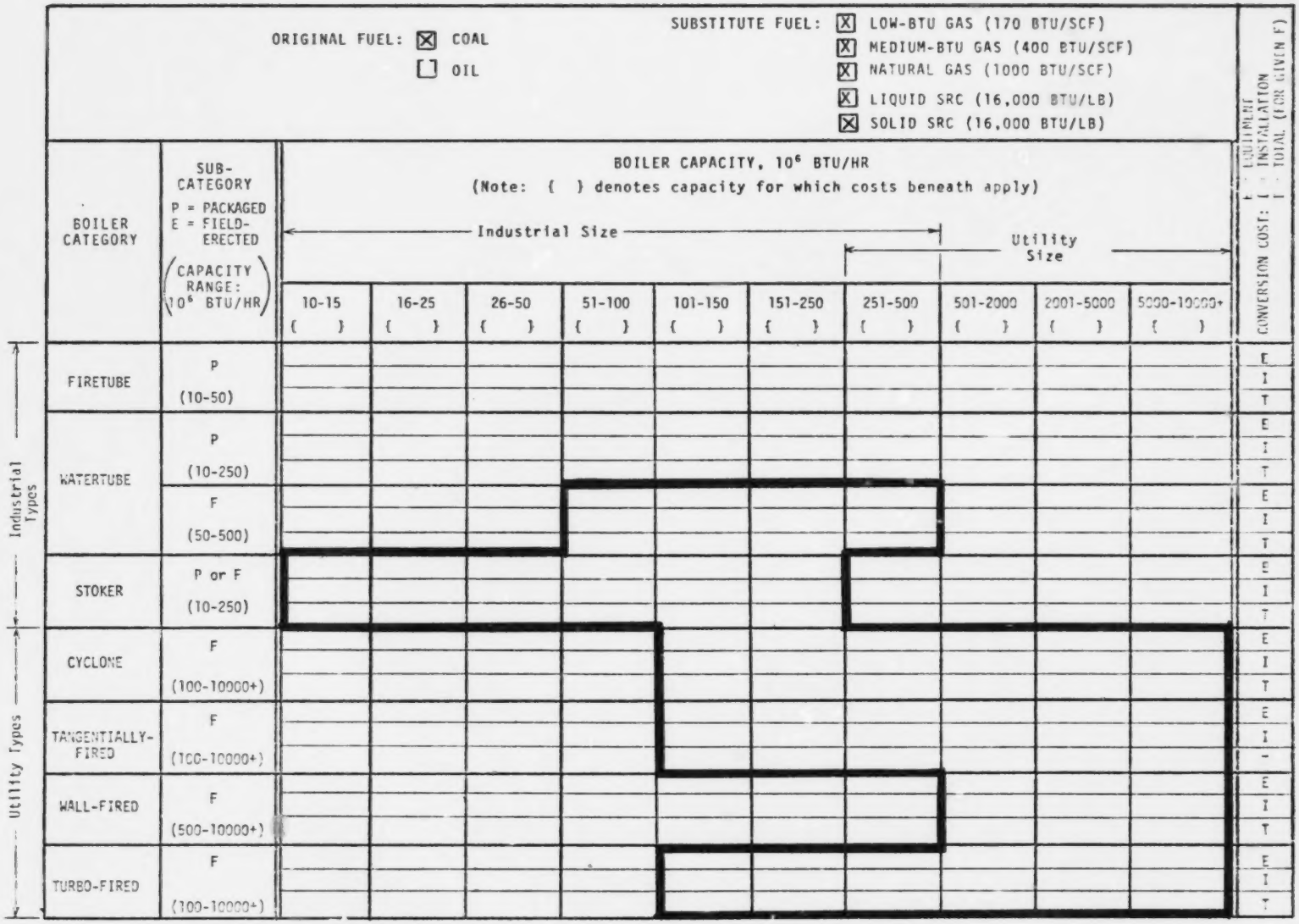

Figure 5-1. Conversion Cost Data Sheet for Coal-Fired Boilers

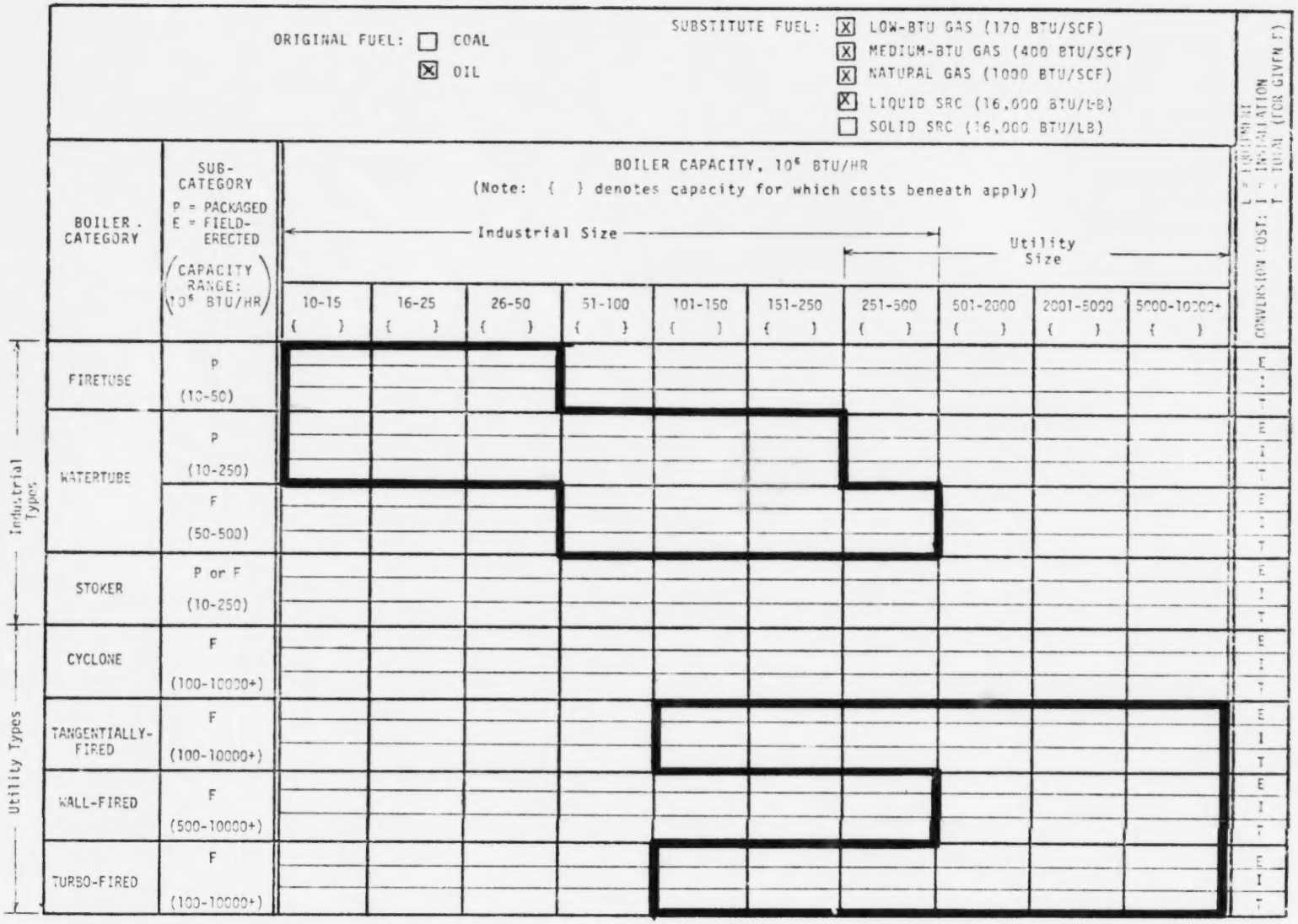
ORIGINAL FUEL: ☐ COAL ☒ OIL
SUBSTITUTE FUEL: ☒ LOW-BTU GAS (170 BTU/SCF) ☒ MEDIUM-BTU GAS (400 BTU/SCF) ☒ NATURAL GAS (1000 BTU/SCF) ☒ LIQUID SRC (16,000 BTU/LB) ☐ SOLID SRC (16,000 BTU/LB)
BOILER CATEGORY
SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10⁶ BTU/HR)
BOILER CAPACITY, 10⁶ BTU/HR
(Note: { } denotes capacity for which costs beneath apply)
Industrial Size
Utility Size
10-15 { } 16-25 { } 26-50 { } 51-100 { } 101-150 { } 151-250 { } 251-500 { } 501-2000 { } 2001-5000 { } 5000-10000+ { }
CONVERSION COST: I = INSTALLATION (FOR GIVEN F)
Industrial Types
Utility Types
FIRETUBE P (10-50)
WATERTUBE P (10-250)
WATERTUBE F (50-500)
STOKER P or F (10-250)
CYCLONE F (100-10000+)
TANGENTIALLY-FIRED F (100-10000+)
WALL-FIRED F (500-10000+)
TURBO-FIRED F (100-10000+)

Figure 5-2. Conversion Cost Data Sheet for Oil-Fired Boilers

SECTION 6

DOCUMENTED BOILER CONVERSION COST DATA

6.1 INTRODUCTION

The preceding section served to define the available fuel substitution options for a given type of boiler. The techniques used to compile the cost data were introduced as well. This section begins with a brief discussion of the major considerations associated with the various types of boiler conversion procedures, continues with the actual cost figures presented in both tabular and graphical form, and concludes with a presentation of the proposed cost models that can be derived from the cost data.

6.2 BOILER MODIFICATION CONSIDERATIONS

This subsection is organized into four portions:

- The general equipment modification considerations prevailing for all of the boiler types
- Some specific points pertaining to certain unique boiler types
- A general discussion of the proposed substitute fuel handling systems
- Descriptions of the firing equipment required for the gaseous and liquid substitute fuels.

6.2.1 General Equipment Modification Considerations Applicable to All Boiler Types

The following are general considerations applicable to all boilers of the indicated type:

- The conversion to the new fuel was planned and implemented in such a manner as not to effect boiler efficiency.
- Existing burner registers can be reused; for coal-fired boilers, the coal nozzles are removed to such a position as to allow adequate working space for installation of new burners.

- The burners selected for gas firing are termed "center-fired" gas guns. Each burner assembly includes a burner gun, guide pipe, shield, flame stabilizing device, flex hose, hand valve, and mounting adapter plate.
- Burners for liquid SRC firing are steam atomizing oil burners of the internal mixing type. (Refer to Table 6-1 for the determination of the number of burners required for the individual boiler capacities chosen for the cost estimations.)
- For converting coal-fired boilers to any of the substitute fuels, a burner management system will be required. The type recommended by the NFPA Supervisory Manual was used. The system includes a logic cabinet, safety interlocks, and all interconnecting piping and wiring. Reference 6-1 supplies additional information on this system. For oil-fired equipment, the existing burner management system can be used, but with new limit and safety interlock settings.
- Existing combustion controls can be reused. Each conversion requires a new fuel flow transmitter, fuel flow rate control valve, and miscellaneous relays and valves to be interfaced with the existing panel.
- It was assumed that no modifications to the boilers' wall-mounted heat transfer surfaces, superheaters, or economizers were required. Indeed, one industrial-size boiler manufacturer stated that their boilers' interior designs for the coal-derived fuels would not differ appreciably from designs presently used for more conventional fossil fuels.
- Existing forced draft and induced draft fans can be reused for the new fuels.
- The assumed gas and liquid SRC supply pressures at the burners are given in Table 6-2. In an existing plant, of course, the supply pressures must be chosen on the basis of practical line size and physical space considerations.

6.2.2 Special Equipment Modification Considerations for Unique Boiler Types

The following are some additional fuel substitution program considerations for five unique categories of boilers.

TABLE 6-1

BOILER TYPES, CAPACITIES, AND ASSOCIATED BURNER QUANTITIES FOR GAS- AND LIQUID SRC-FIRING

Boiler Category	Capacity (10^6Btu/hr)	Burner Quantity	Capacity (10^6Btu/hr)	Burner Quantity	Capacity (10^6Btu/hr)	Burner Quantity
Fire Tube	12	1	20	1	35	1
Watertube (field-erect.)	75	1	150	2	350	4
Watertube (packaged)	25	1	75	1	150	2
Stoker	25	1	75	1	150	2
Cyclone	250	2	1,000	8	7500	60
Tangentially-fired	250	2	1,000	8	7500	60
Wall-fired	1,000	8	3,500	28	7500	60
Turbo-fired	250	2	1,000	8	7500	60

TABLE 6-2

BURNER SUPPLY PRESSURES FOR GASEOUS
AND LIQUID SUBSTITUTE FUELS

Substitute Fuel Type	Burner Supply Pressure (psig)
Low-Btu gas	35 - 40
Medium-Btu gas	30
Natural gas	15
Liquid SRC	125

6.2.2.1 Firetube Boilers

It was assumed that an industrial-type flame safeguard system exists and is reusable. Gas safety interlocks and a fuel selector switch are added. In addition, it was assumed that the existing burner guns are steam- or high pressure air-atomized, and not mechanical atomized.

6.2.2.2 Stoker-Fired Boilers

For the purposes of this study, it was assumed that the mechanical stoker and internal grates would be removed and a new twelve inch-thick refractory floor would be installed. A completely new windbox-burner assembly would be installed in the lower front wall. The actual number of burners needed depends on the furnace capacity.

In some cases, the more economical approach would be to install the refractory directly on the existing grates, and mount the windbox burner in the boiler's sidewall. However, this would require bending of the heat transfer tubes in the vicinity of the burner to afford clearance for the burner throat. The disadvantages of this approach are operator inconvenience, possible water circulation problems due to the unusual tube bends, and minor problems in adjusting the flame shape to retain a uniform temperature profile across the boiler tube bank or superheater (if employed).

As a general rule, the retrofitted burner can be supplied with an integral fan rather than attempting to reuse the existing combustion air fan. This is because the fan cost is offset by the labor, materials, and engineering required for the installation of a duct from the existing fan to the new burner.

For solid SRC, the only practical conversion strategy would be to install a suspended firing system as is described above. Due to its rather low melting temperature (260F), the SRC would be incompatible with the stoker's grates, which are designed for bed-type combustion with concurrent removal of incombustible ash and char.

6.2.2.3 Cyclone-Fired Utility Boilers

For retrofitting this class of boiler to the gaseous or liquid coal-derived fuels, the new burner guns can be installed through the existing coal burner. It was assumed that the average cyclone furnace heat release rate was 250×10^6 Btu/hr. Capacities of larger boilers would be multiples of this figure, and would require a correspondingly larger number of individual cyclone furnaces. It was assumed that on liquid SRC firing above 200×10^6 Btu/hr, two simultaneously-firing oil atomizers will be used, because this heat release quantity is currently the upper limit of a single atomizer as currently designed.

The existing combustion control system can be used, but will require the addition of a fuel flow control valve for each cyclone furnace.

6.2.2.4 Turbo- or Tangentially-Fired Utility Boilers

For oil-fired boilers of these types, retrofit of the gases and liquid SRC will involve the installation of the burners ("gun" design) either in a parallel (tangentially-fired) or an adjacent (turbo-fired) configuration. In coal-fired units, the guns can be substituted in place of the existing coal burner tubes and nozzles.

There may occur a small difference in piping installation costs between the tangentially- and turbo-fired boilers due to running the piping vertically versus horizontally. This variation, however, was considered insignificant in light of the other plumbing costs, such as valve installation.

6.2.3 Fuel Handling Systems

In the determination of piping costs for the gaseous substitute fuels, it was assumed that the amount of piping installed could be grouped into three categories, the length being an arbitrary function of the boiler capacity. Therefore, the piping to the boiler is essentially independent of boiler type. The capacities and respective pipe runs are given in Table 6-3 (A).

The second general assumption made for the gaseous fuel handling systems was that the piping supplied a single boiler. The third and possibly most important assumption was made in regard to the pressures of each type of gas as supplied to the steam plant boundary. This information is given in Table 6-3(B). These pressures were selected because they appeared to be commercially practical, and because the line sizes more closely match existing industrial standards. It is obvious that the variation in the main gas supply pressure could effect the validity of the cost estimates; this is especially true in the case of low-Btu gas.

For solvent refined coal (SRC) in the hot liquid state, complete heating systems are required for both the SRC storage facilities and the burner supply piping system. A liquid heat transfer system using Therminol 77 was selected for these purposes (see Reference 6-2 for Therminol's properties). This heat transfer fluid is heated by firing No. 2 fuel oil in a firetube boiler on the plant premises. The hot Therminol is then used to warm the storage tanks and the day tanks, to supply the suction heaters, and to heat trace all piping and valves. It was assumed that the SRC would be delivered at 450F, all pumping would be done at 1100 centistokes, and that the SRC would arrive at the

TABLE 6-3

GASEOUS FUEL HANDLING SYSTEM PIPING LENGTHS AND SUPPLY PRESSURES

(A) Piping Length, All Gases

Boiler Capacity Range (10^6 Btu/hr)	Piping Length (ft)
10-65	500
75-350	1000
500-7500	2000

(B) Supply Pressure to Plant Boundary

Gaseous Fuel Type	Supply Pressure (psig)
Low-Btu	350
Medium-Btu	130
Natural	50

burner at 66 centistokes (640F). Each system includes the following features:

- An unloading pump set of capacity equal to six times the firing rate
- Insulated bulk storage tank(s) for the liquid SRC and No. 2 fuel oil, with an estimated thirty day storage capacity
- Tank foundations and firewalls
- Tank suction heater(s)
- Therminol heaters and circulation pumps
- No. 2 oil pump sets
- SRC transfer pump set
- Insulated SRC day tank (two day storage capacity)
- Day tank suction heater
- Final pump and heater set
- All necessary interconnecting piping and valves

For solid SRC, the costs of converting coal-fired boilers will reflect the requirement that various portions of the fuel handling system be externally cooled, by either water or air. It was assumed that the existing coal handling and preparation equipment could be used with no major modifications necessary. Air preheat operation would be discontinued and replaced by a system supplying ambient or chilled air for coal conveying purposes. It was also assumed that the coal supply pipe at the burner would be water-cooled.

6.2.4 Firing Equipment For Gases and Liquid SRC

This subsection contains more detailed information on the replacement firing equipment for the gaseous and liquid substitute fuels, including:

- Burner types
- Burner fuel supply valving
- Burner management systems

For conversions of coal-fired combustion systems to the use of solid SRC, it was assumed that the existing firing equipment with the retrofits described previously would be adequate for the purpose. For these boilers, major modification costs will be associated only with the fuel handling system.

6.2.4.1 Burner Types

For gaseous substitute fuel firing, the burner selected was the center-fired gas gun. Table 6-4 shows the gun sizes chosen for the various gases.

To burn liquid SRC, a burner of the multiple venturi design was deemed practical. This is a steam-atomized burner normally used for heavy fuel oil (No. 6) combustion applications. Table 6-5 lists the model numbers and corresponding heat release rates of a typical commercially-available multiple venturi burner. Similarly-designed burners are available from a number of manufacturers.

6.2.4.2 Burner Fuel Supply Valving

The following are typical valve requirements for single and multiple burner applications:

Single Burner, Gas-Fired

Pilot gas cock, pilot gas PRV, two pilot safety shut-offs, one pilot gas vent, main gas safety shut-off, supervisory gas plug cock, and main gas fuel flow control valve.

Single Burner, Liquid SRC-Fired

Main oil safety shut-off, main oil check, supervisory oil cock, steam purge, steam check, manual oil shut-off, manual steam shut-off, oil strainer steam drain, steam trap, steam-oil pressure differential control, and main oil flow control valve; pilot valves are the same as for gas.

Multiple Burners, Gas-Fired

The following valves are required at the header: main gas strainer, manual shut-off, main gas PRV, bypass PRV, main safety shut-off, main gas header vent, two manual gas vent valves, main gas reliefs, pilot gas manual shut-off, pilot gas PRV, and one main gas control valve.

The following valves are required at each burner: burner safety shut-off, supervisory shut-off cock, two pilot gas safety shut-offs, and one pilot gas vent valve.

Multiple Burners, Liquid SRC-Fired

The following header valves are required: manual oil shut off, oil strainer, main oil safety shut-off, oil by-pass PRV, oil return check valve, oil recirculating valve, steam manual shut-off, steam strainer, steam trap, steam PRV, steam bleed check, steam-oil differential pressure, oil flow control valve, manual pilot gas valve, and pilot gas PRV.

TABLE 6-4

GUN SIZES FOR GASEOUS SUBSTITUTE FUEL FIRING
(NOMINAL PIPE SIZE, INCHES)

Gaseous Fuel Type \ Burner Firing Rate (10^6Btu/hr)	25	75	125
Low-Btu gas	4	6	8
Medium-Btu gas	3	4	6
Natural gas	2	3	4

TABLE 6-5

TYPICAL MULTIPLE VENTURI BURNER TYPES
FOR LIQUID SRC FIRING
(MANUFACTURER: THE COEN CO.,REFERENCE 6-3)

Coen Co. Model Number	Maximum Heat Release Rate (10^6Btu/hr)
1 MV	35
2 MV	75
3 MV	150
3-1/2 MV	350
Dual 3 MV or 3-1/2 MV	> 350

The following valves are required at each individual burner: burner safety shut-off, oil check, supervisory oil cock, steam purge, steam check, steam manual shut-off, two pilot gas safety shut-offs, and one pilot gas vent valve.

6.2.4.3 Burner Management System

Converting from coal to gaseous substitute fuels requires the addition of at least the following safety interlocks: high gas pressure, low gas pressure, forced draft air, purge air, instrument air, fan starter interlocks, damper position switches for the forced and induced draft fans (if used), and steam over-pressure. Converting from coal to liquid SRC requires basically the same except for low oil pressure and temperature limit switches. Atomizing steam pressure and flow switches are also required. For multiple burner applications, such as in utility boilers, header switches are included in addition to the individual burner fuel interlocks.

6.3 BOILER CONVERSION COST DATA AND EVALUATION

6.3.1 Introduction

The previous subsection presented the basic assumptions on which the boiler conversion cost estimations were based. The present subsection contains these cost figures, tabulated on the data sheet first introduced in Section 5 of this report. In order to visualize more clearly the functional relationship between conversion cost and capacity for a given boiler, these data are plotted for each original fuel-to-substitute fuel conversion. A discussion of the data and their concomitant uncertainty factors is given as well.

6.3.2 Boiler Conversion Cost Data

Tables 6-6 through 6-14 are the completed data sheets for all nine possible conversions: coal-fired equipment modified to burn all five coal-derived fuels, and the oil-fired equipment modified to burn four out of the five substitute fuels (excluding solid SRC). It should be remembered that "liquid SRC" refers to the melted solid SRC material. The installation costs are based on 1974 San Francisco Bay Area labor rates. The total capital costs, or required plant investment, indicated on the tables are therefore specific for that metropolitan area. These numbers must be modified by a location factor if the installation costs for another site are desired. This point will be discussed further in subsection 6.3.4. All of these cost figures were reduced from the bulk cost data included in the Appendix of this report. These figures are

sums of numbers from individual modification considerations; the last three digits are not significant.

Associated with each of these tables are the corresponding data plots, Figures 6-1 through 6-9. Table 6-15 presents the uncertainty factors for the conversion costs. These confidence limits are indicated on the plots by the vertical bars on each point. Some error bars, however, are not included since they would have been of insignificant length when drawn on the log-log graph.

Figure 6-10 is the composite of all the data. Superimposed on these points are straight lines showing cost as a function of capacity for all boiler types. The overall significance of the conversion cost data is discussed in the following subsection.

6.3.3 Cost Data Evaluation

Within the scatter of the data plotted in Figures 6-1 to 6-9 there is a correspondence between conversion cost and capacity for individual boiler types. In addition, a general correspondence between conversion cost and capacity exists for all boiler types for a given original fuel to substitute fuel conversion. The data appear to be described by power law functional relationships. The following are some additional significant items that require amplification:

- For the gaseous substitute fuels, boiler conversion costs increase in proportion to a decrease in heating value of the fuel (Figures 6-1 through 6-3, 6-6 through 6-8). The greatest cost differential exists for 750 MW equipment, for which a 45% cost variance exists.
- In some of the plots, the data points for stoker-fired equipment lie above the correspondence defined by the remaining points (Figures 6-1 through 6-3). This reflects the additional cost incurred as a result of the required internal modifications, a procedure unique to this type of boiler.
- The data points for oil-fired, firetube boilers (Figures 6-6 through 6-9) indicate a slightly different trend than that defined by the remaining points. This reflects certain fixed costs, such as piping common to all types of boilers, which become more noticeable as the boiler's physical size and capacity decrease.
- For all of the original fuel-to-substitute fuel conversions, the costs required to modify the utility boilers differ among the various types of boilers only slightly. This is at variance with the notion conceived previous to compiling the data that conversion cost would be a strong function of utility boiler type. The costs associated with the individual conversion considerations for each type of boiler are contained in the Appendix of this report.

TABLE 6-6
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: [X] COAL [ ] OIL

SUBSTITUTE FUEL: [X] LOW-BTU GAS (170 BTU/SCF) [ ] MEDIUM-BTU GAS (400 BTU/SCF) [ ] NATURAL GAS (1000 BTU/SCF) [ ] LIQUID SRC (16,000 BTU/LB) [ ] SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			Industrial Size →						Utility Size →				
			10-15 { }	16-25 { 25 }	26-50 { }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)											E
													I
													T
	WATERTUBE	P (10-250)											E
													I
													T
		F (50-500)				22870	49085		83040				E
						18130	43970		68270				I
						41000	93055		151310				T
	STOKER	P or F (10-250)		26250		26800	75435						E
				34780		58470	101430						I
				61030		95270	176865						T
Utility Types	CYCLONE	F (100-10000+)						59985		204205		1068350	E
								69460		241890		811690	I
								129445		446095		1880040	T
	TANGENTIALLY-FIRED	F (100-10000+)						59985		206205		1073850	E
								69380		241990		798230	I
								129365		448195		1872080	T
	WALL-FIRED	F (500-10000+)								206375	526655	1073850	E
										241630	411350	798030	I
										448005	938005	1871880	T
	TURBO-FIRED	F (100-10000+)						59985		206205		1073850	E
								69380		241990		798230	I
								129365		448195		1872080	T

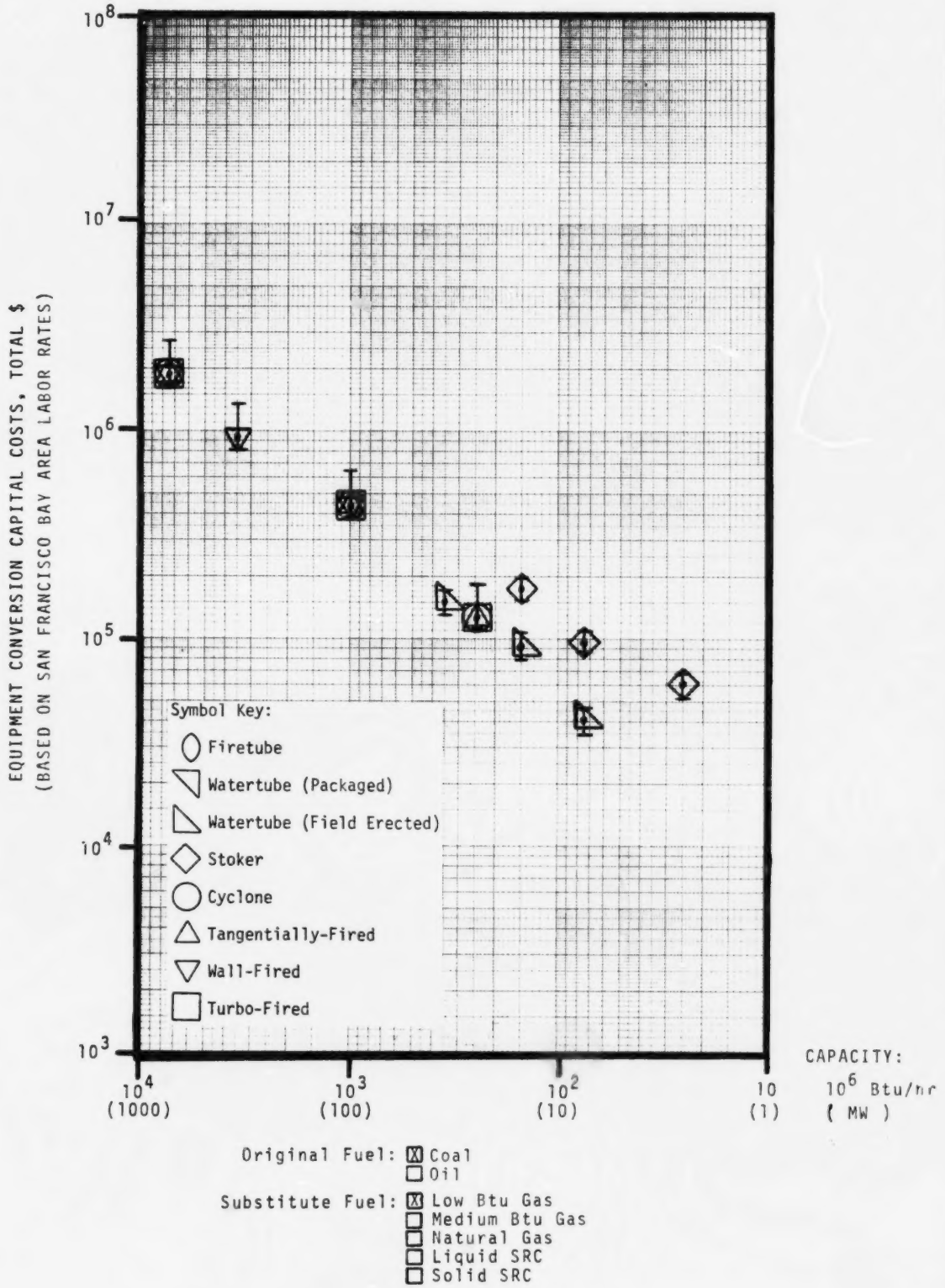

Figure 6-1. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-7
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: [X] COAL [ ] OIL

SUBSTITUTE FUEL: [ ] LOW-BTU GAS (170 BTU/SCF) [X] MEDIUM-BTU GAS (400 BTU/SCF) [ ] NATURAL GAS (1000 BTU/SCF) [ ] LIQUID SRC (16,000 BTU/LB) [ ] SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			Industrial Size						Utility Size				
			10-15 { }	16-25 { 25 }	26-50 { }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)											E
													I
													T
	WATERTUBE	P (10-250)											E
													I
													T
		F (50-500)				18850	44710		69415				E
						16960	42685		67230				I
						35810	87395		136645				T
	STOKER	P or F (10-250)		23240		32500	69060						E
				34180		57460	100580						I
				57420		89960	169640						T
Utility Types	CYCLONE	F (100-10000+)						54660		163875		858245	E
								64280		213870		610640	I
								118940		377745		1468885	T
	TANGENTIALLY-FIRED	F (100-10000+)						54760		163475		842725	E
								64830		214500		561940	I
								119590		377975		1404665	T
	WALL-FIRED	F (500-10000+)								163675	436660	842725	E
										214500	369010	561940	I
										378175	805670	1404665	T
	TURBO-FIRED	F (100-10000+)						54760		163475		842725	E
								64830		214500		561940	I
								119590		377975		1404665	T

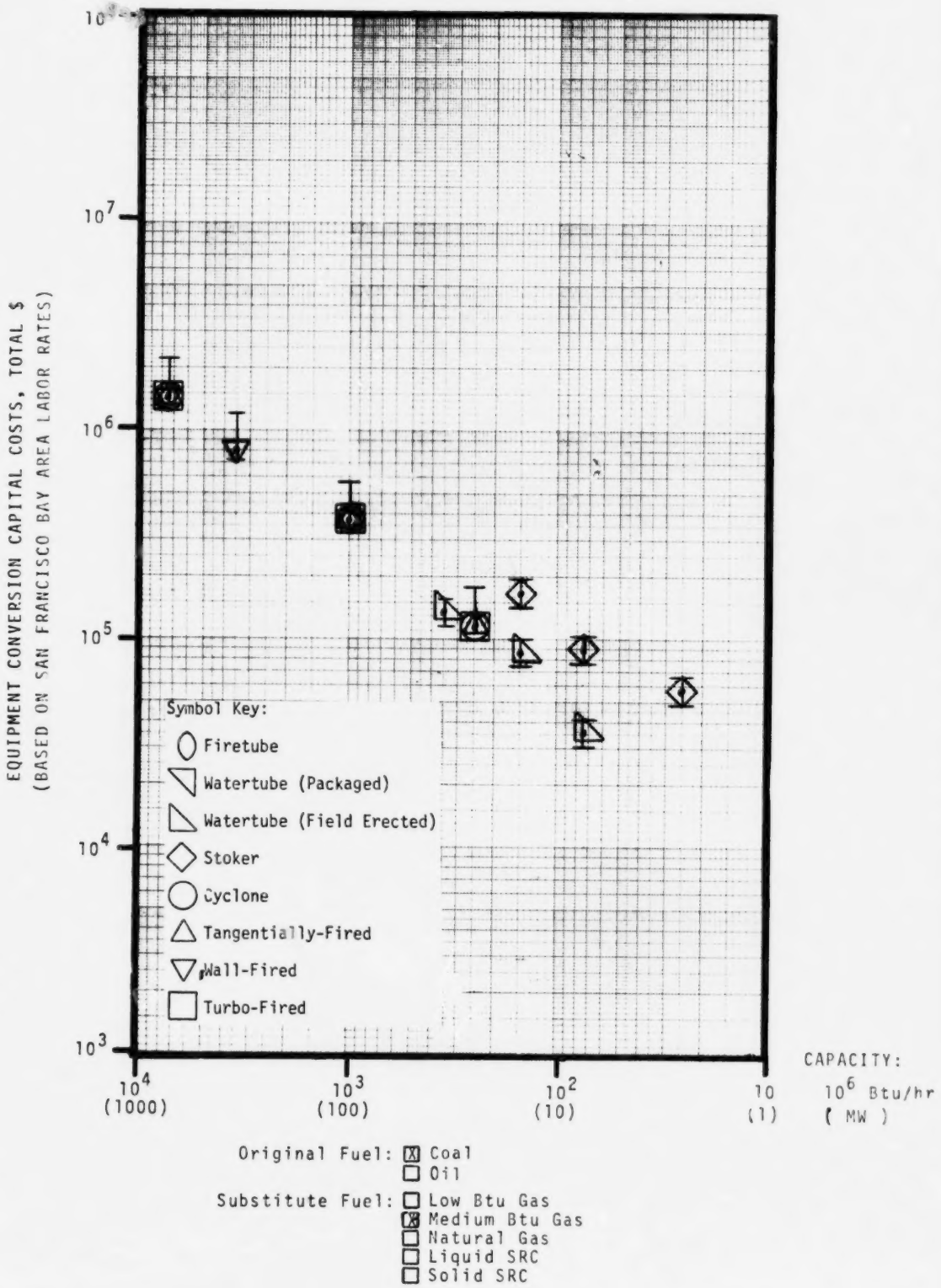

Figure 6-2. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-8
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: [X] COAL [ ] OIL

SUBSTITUTE FUEL: [ ] LOW-BTU GAS (170 BTU/SCF) [ ] MEDIUM-BTU GAS (400 BTU/SCF) [X] NATURAL GAS (1000 BTU/SCF) [ ] LIQUID SRC (16,000 BTU/LB) [ ] SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			Industrial Size						Utility Size				
			10-15 { }	16-25 { 25 }	26-50 { }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)											E
													I
													T
	WATERTUBE	P (10-250)											E
													I
													T
		F (50-500)				15570	34025		52795				E
						16430	42175		65930				I
						32000	76200		118725				T
	STOKER	P or F (10-250)		22045		30370	56875						E
				33860		57070	99430						I
				55905		87440	158105						T
Utility Types	CYCLONE	F (100-10000+)						41165		143665		733525	E
								59590		209870		562470	I
								100755		353535		1295995	T
	TANGENTIALLY-FIRED	F (100-10000+)						40915		143855		813285	E
								58640		207430		558030	I
								99555		351285		1371315	T
	WALL-FIRED	F (500-10000+)								104055	364890	813285	E
										207730	315390	558030	I
										311785	680280	1371315	T
	TURBO-FIRED	F (100-10000+)						40915		143755		813285	E
								58640		207430		558030	I
								99555		351185		1371315	T

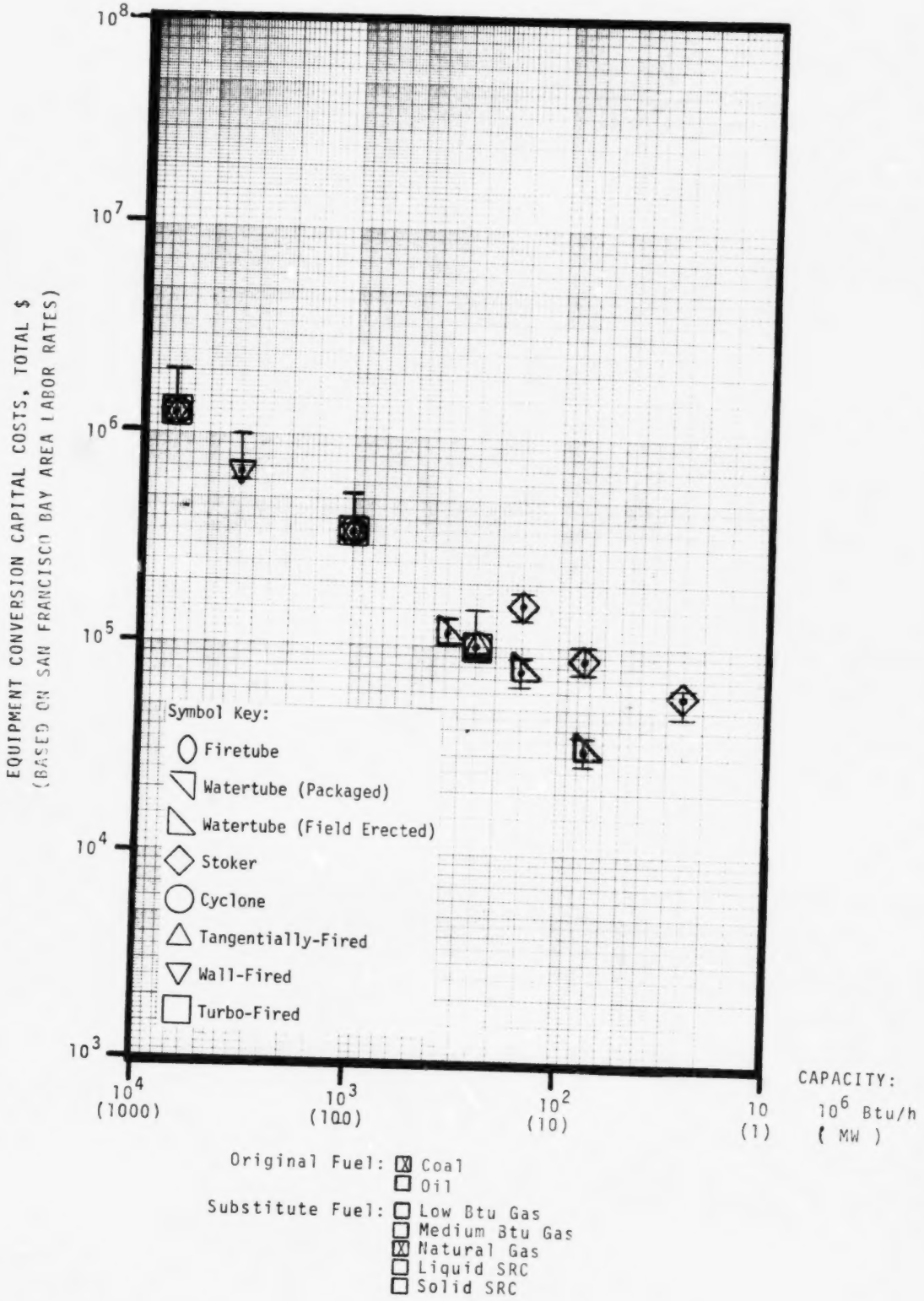

Figure 6-3. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-9
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: [X] COAL [ ] OIL

SUBSTITUTE FUEL: [ ] LOW-BTU GAS (170 BTU/SCF) [ ] MEDIUM-BTU GAS (400 BTU/SCF) [ ] NATURAL GAS (1000 BTU/SCF) [X] LIQUID SRC (16,000 BTU/LB) [ ] SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			Industrial Size →						Utility Size →				
			10-15 { }	16-25 { 25 }	26-50 { }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)											E
													I
													T
	WATERTUBE	P (10-250)											E
													I
													T
		F (50-500)				299425	386630		750120				E
						414350	599255		1473650				I
						713775	985885		2223770				T
	STOKER	P or F (10-250)		160930		310375	407880						E
				247870		438880	636755						I
				408800		749255	1044636						T
Utility Types	CYCLONE	F (100-10000+)						499905		1668000		14723020	E
								881430		3526700		23691480	I
								1381353		5194700		38414500	T
	TANGENTIALLY-FIRED	F (100-10000+)						496505		1722480		15107200	E
								884540		3716030		24065480	I
								1381045		5438510		39172680	T
	WALL-FIRED	F (500-10000+)								1716320	5762020	15128200	E
										3716030	11131680	24284380	I
										5432350	16893700	39412580	T
	TURBO-FIRED	F (100-10000+)						496505		1668000		14723020	E
								884540		3526700		23691480	I
								1381045		5194700		38414500	T

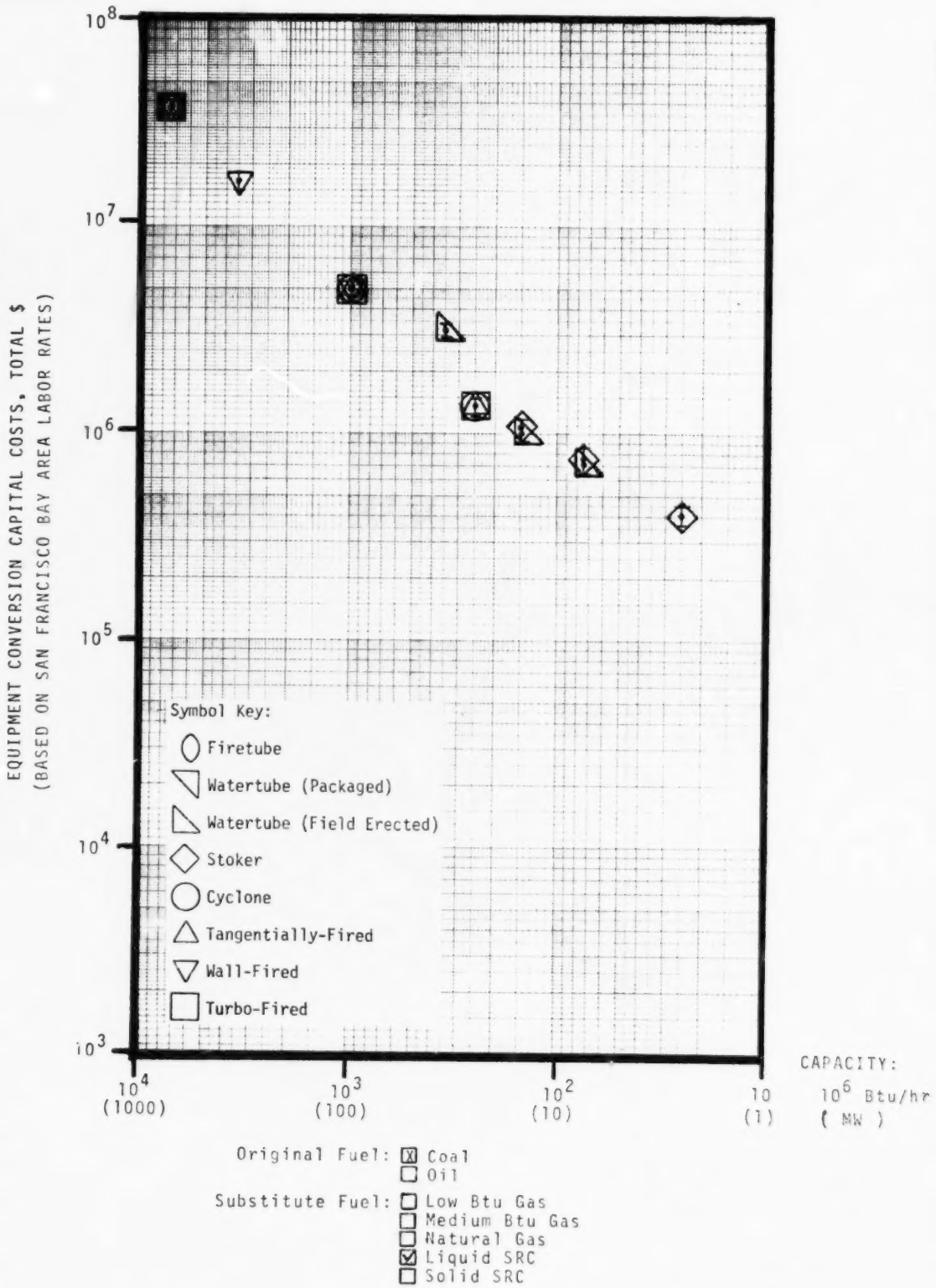

Figure 6-4. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-10
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: [X] COAL [ ] OIL

SUBSTITUTE FUEL: [ ] LOW-BTU GAS (170 BTU/SCF) [ ] MEDIUM-BTU GAS (400 BTU/SCF) [ ] NATURAL GAS (1000 BTU/SCF) [ ] LIQUID SRC (16,000 BTU/LB) [X] SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			Industrial Size →						Utility Size →				
			10-15 { }	16-25 { }	26-50 { }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)											E
													I
													T
	WATERTUBE	P (10-250)											E
													I
													T
		F (50-500)				16825	28000		43400				E
						10000	15800		26400				I
						25825	43800		69800				T
	STOKER	P or F (10-250)				16825	28000						E
						10000	15800						I
						26825	43800						T
Utility Types	CYCLONE	F (100-10000+)						31000		86740		345000	E
								18800		56000		215000	I
								49800		142740		560000	T
	TANGENTIALLY-FIRED	F (100-10000+)						31000		86740		345000	E
								18800		56000		215000	I
								49800		142740		560000	T
	WALL-FIRED	F (500-10000+)								86740	186000	345000	E
										56000	114000	215000	I
										142740	300000	560000	T
	TURBO-FIRED	F (100-10000+)						31000		86740		345000	E
								18800		56000		215000	I
								49800		142740		560000	T

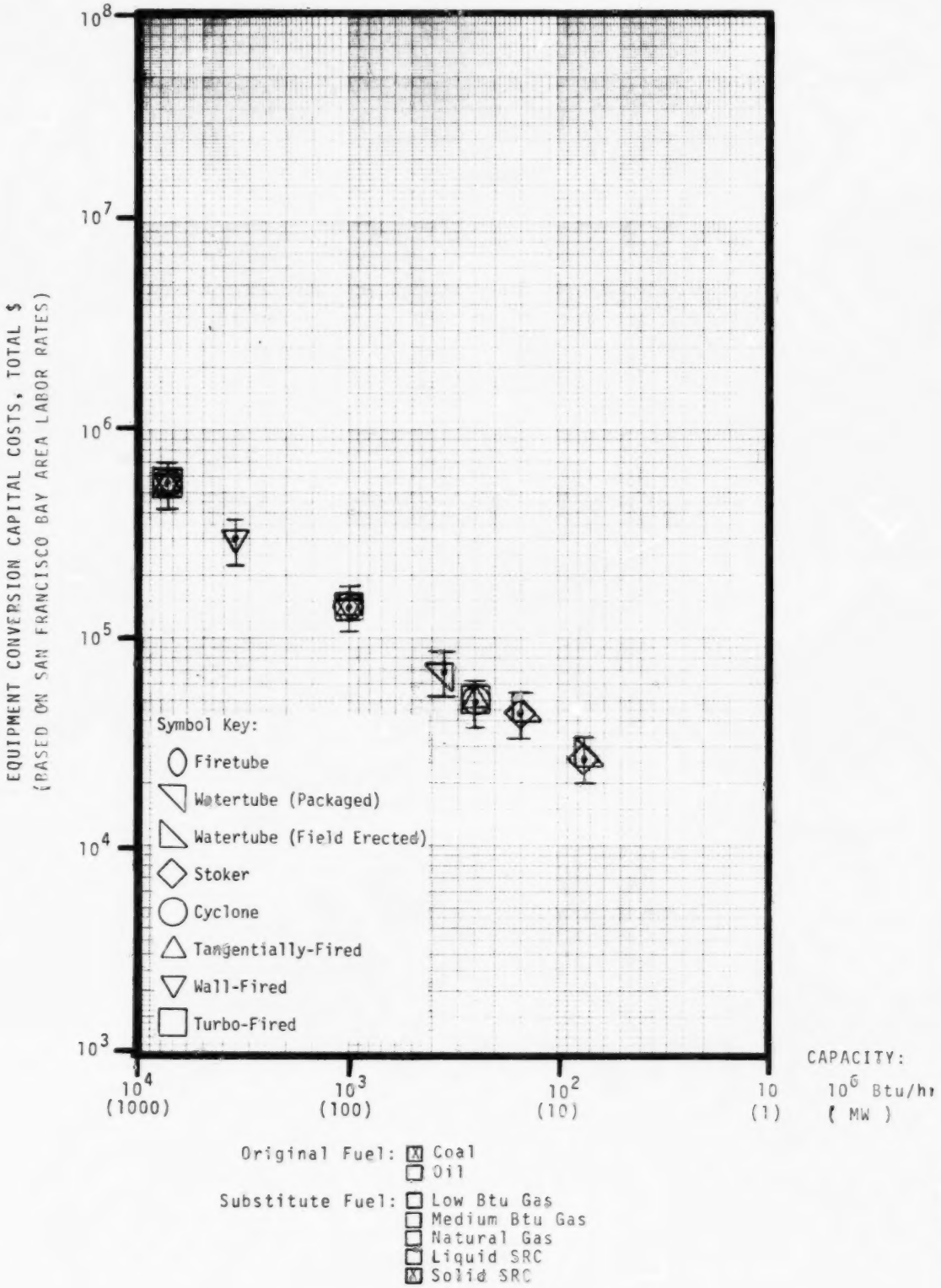

Figure 6-5. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-11
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: ☐ COAL ☒ OIL

SUBSTITUTE FUEL: ☒ LOW-BTU GAS (170 BTU/SCF) ☐ MEDIUM-BTU GAS (400 BTU/SCF) ☐ NATURAL GAS (1000 BTU/SCF) ☐ LIQUID SRC (16,000 BTU/LB) ☐ SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			← Industrial Size →						Utility Size →				
			10-15 { 12 }	16-25 { 20 }	26-50 { 35 }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)	11425	13175	14975								E
			7575	8275	8825								I
			19000	21450	23600								T
	WATERTUBE	P (10-250)		14000		17750	41035						E
				8300		16910	42330						I
				22300		34660	83365						T
		F (50-500)				16850	39035		68290				E
						16910	42330		65055				I
						33760	81365		133345				T
	STOKER	P or F (10-250)											E
													I
													T
Utility Types	CYCLONE	F (100-10000+)											E
													I
													T
	TANGENTIALLY-FIRED	F (100-10000+)						47120		167005		789570	E
								65765		226490		685945	I
								112885		393495		1475515	T
	WALL-FIRED	F (500-10000+)								169175	389070	789570	E
										226130	358015	685745	I
										395305	747085	1475315	T
	TURBO-FIRED	F (100-10000+)						47120		167005		789570	E
								65765		226490		685945	I
								112885		393495		1475515	T

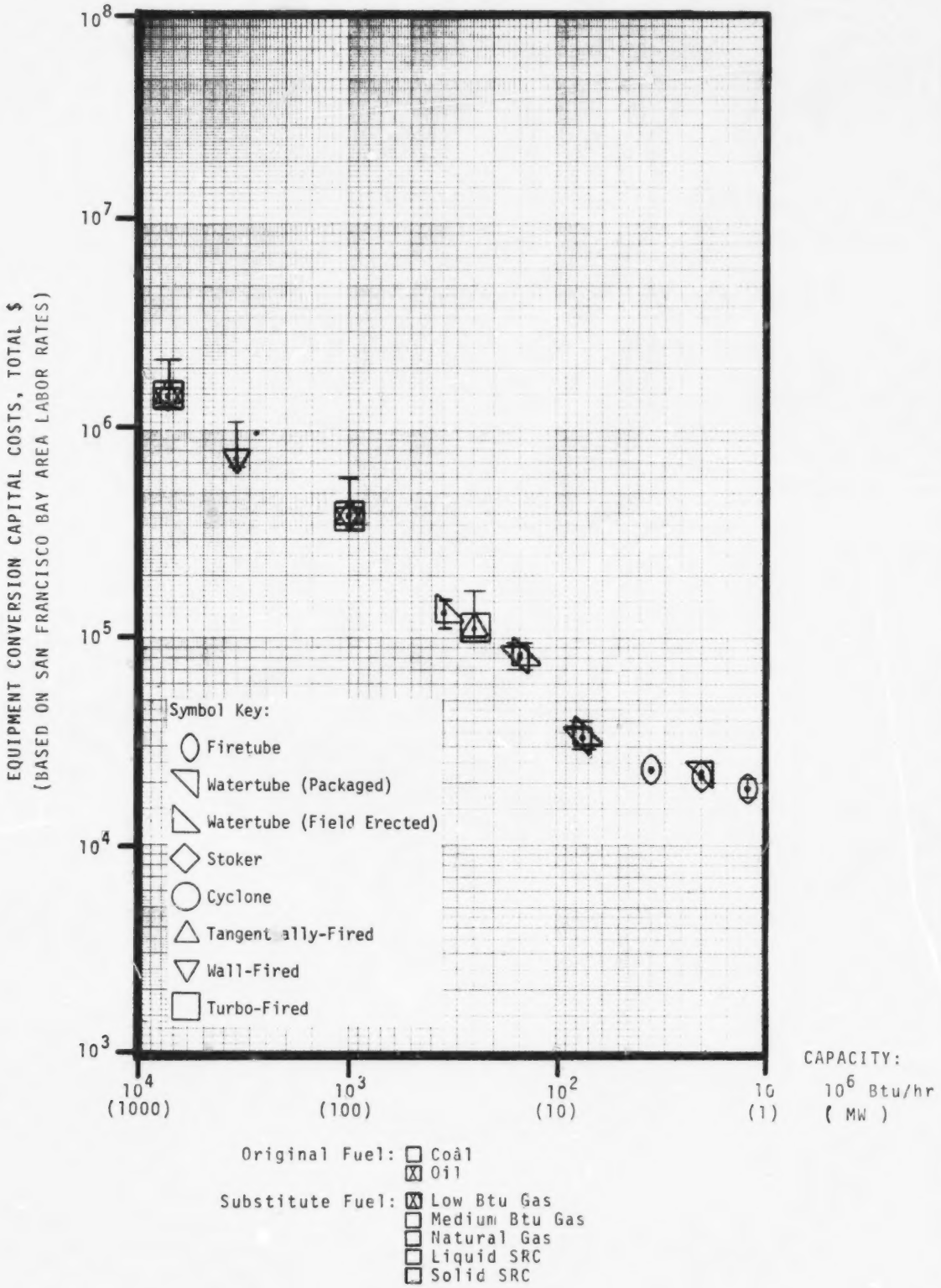

Figure 6-6. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-12
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: ☐ COAL ☒ OIL

SUBSTITUTE FUEL: ☐ LOW-BTU GAS (170 BTU/SCF) ☒ MEDIUM-BTU GAS (400 BTU/SCF) ☐ NATURAL GAS (1000 BTU/SCF) ☐ LIQUID SRC (16,000 BTU/LB) ☐ SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			Industrial Size →						Utility Size →				
			10-15 { 12 }	16-25 { 20 }	26-50 { 35 }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000 }	2001-5000 { 3500 }	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)	7425	8725	9875								E
			6475	6625	6725								I
			13900	15350	16000								T
	WATERTUBE	P (10-250)		9000		14080	37860						E
				6650		15675	41095						I
				15650		29755	78955						T
		F (50-500)				13280	35360		54265				E
						15675	41095		58950				I
						28955	76455		113215				T
	STOKER	P or F (10-250)											E
													I
													T
Utility Types	CYCLONE	F (100-10000+)											E
													I
													T
	TANGENTIALLY-FIRED	F (100-10000+)						41895		124275		555445	E
								61215		199000		449655	I
								103110		323275		1005100	T
	WALL-FIRED	F (500-10000+)								124470	293075	588443	E
										199000	315675	449655	I
										323470	608750	1008098	T
	TURBO-FIRED	F (100-10000+)						41895		124275		558445	E
								61215		199000		449655	I
								103110		323275		1008100	T

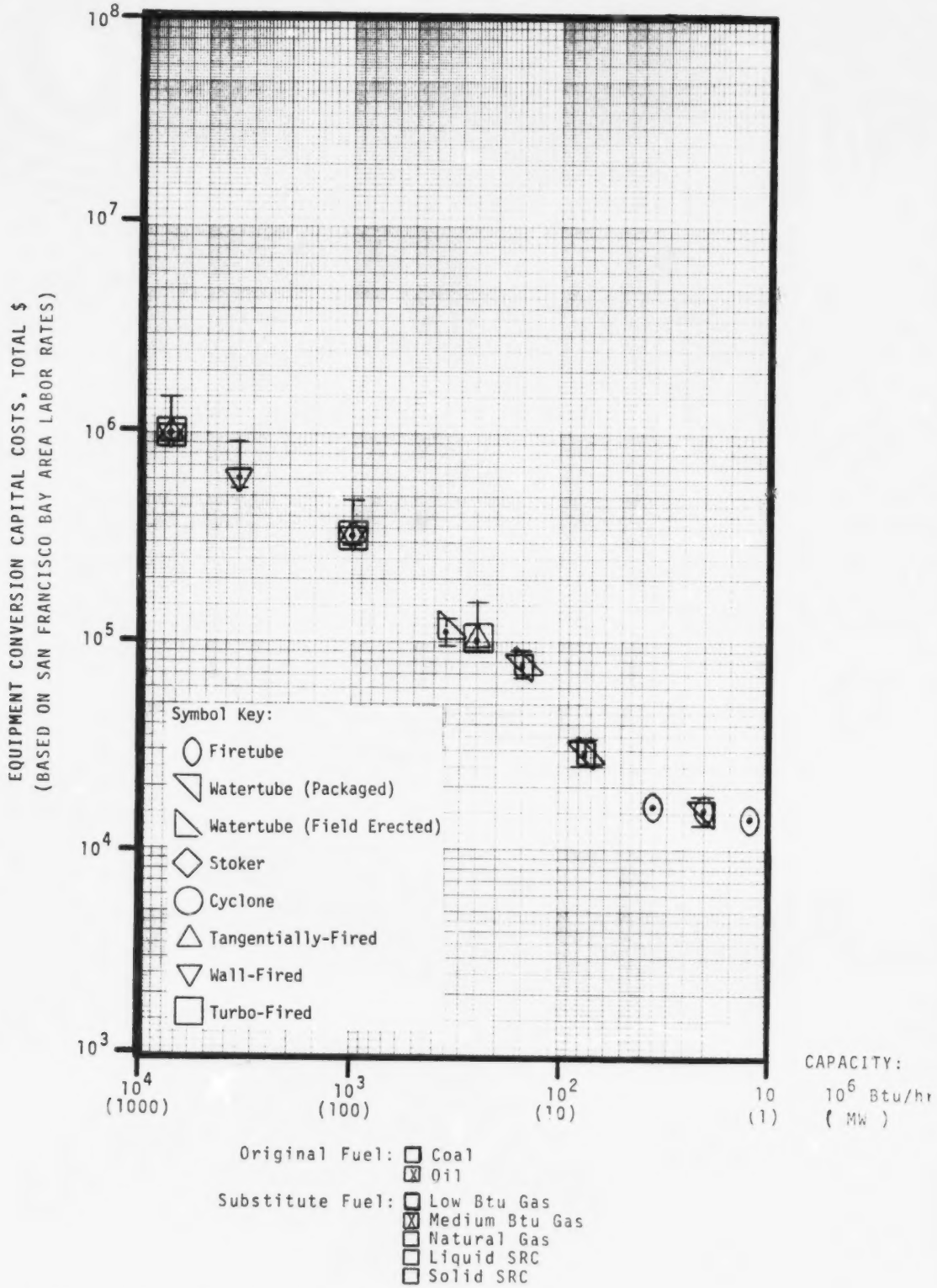

Figure 6-7. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-13
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: ☐ COAL ☒ OIL

SUBSTITUTE FUEL: ☐ LOW-BTU GAS (170 BTU/SCF) ☐ MEDIUM-BTU GAS (400 BTU/SCF) ☒ NATURAL GAS (1000 BTU/SCF) ☐ LIQUID SRC (16,000 BTU/LB) ☐ SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			← Industrial Size →						Utility Size →				
			10-15 { 12 }	16-25 { 20 }	26-50 { 35 }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 { 1000}	2001-5000 { 3500}	5000-10000+ { 7500 }	
Industrial Types	FIRETUBE	P (10-50)	6075	7125	8525								E
			6350	6450	6575								I
			12425	13575	15100								T
	WATERTUBE	P (10-250)		8000		10320	24775						E
				6500		15150	40370						I
				14500		25470	65145						T
		F (50-500)				9720	23175		37445				E
						15150	40370		57290				I
						24870	63545		94735				T
	STOKER	P or F (10-250)											E
													I
													T
Utility Types	CYCLONE	F (100-10000+)											E
													I
													T
	TANGENTIALLY-FIRED	F (100-10000+)						28050		104655		529000	E
								55025		191930		445745	I
								83075		296585		974745	T
	WALL-FIRED	F (500-10000+)								104855	227305	529005	E
										192230	262055	445745	I
										297085	489360	974750	T
	TURBO-FIRED	F (100-10000+)						28050		10465		529000	E
								55025		191930		445745	I
								83075		296585		974745	T

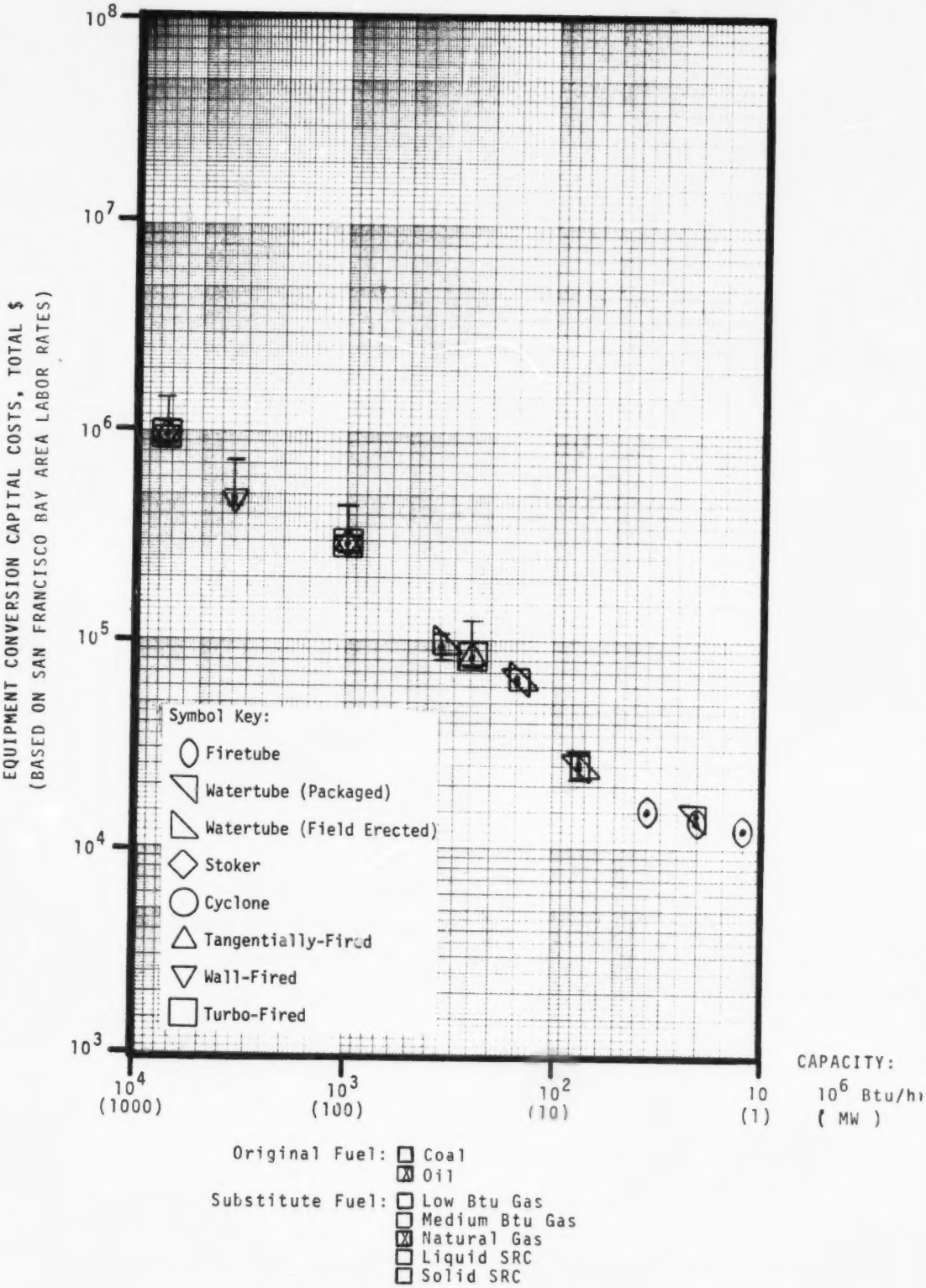

Figure 6-8. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-14
EQUIPMENT CONVERSION CAPITAL COSTS ($)

ORIGINAL FUEL: ☐ COAL ☒ OIL

SUBSTITUTE FUEL: ☐ LOW-BTU GAS (170 BTU/SCF) ☐ MEDIUM-BTU GAS (400 BTU/SCF) ☐ NATURAL GAS (1000 BTU/SCF) ☒ LIQUID SRC (16,000 BTU/LB) ☐ SOLID SRC (16,000 BTU/LB)

	BOILER CATEGORY	SUB-CATEGORY P = PACKAGED E = FIELD-ERECTED (CAPACITY RANGE: 10^6 BTU/HR)	BOILER CAPACITY, 10^6 BTU/HR (Note: { } denotes capacity for which costs beneath apply)										CONVERSION COST: E = EQUIPMENT I = INSTALLATION T = TOTAL (FOR GIVEN F)
			← Industrial Size →						Utility Size →				
			10-15 { 12 }	16-25 { 20 }	26-50 { 35 }	51-100 { 75 }	101-150 { 150 }	151-250 { 250 }	251-500 { 350 }	501-2000 {1000 }	2001-5000 {3500 }	5000-10000+ {7500 }	
Industrial Types	FIRETUBE	P (10-50)	123000	134000	145000								E
			175000	212000	231000								I
			298000	346000	376000								T
	WATERTUBE	P (10-250)		140000		298075	383655						E
				220000		412440	597195						I
				360000		710515	980850						T
		F (50-500)				296075	379655		735620				E
						412940	597195		1489270				I
						709015	976850		2204890				T
	STOKER	P or F (10-250)											E
													I
													T
Utility Types	CYCLONE	F (100-10000+)											E
													I
													T
	TANGENTIALLY-FIRED	F (100-10000+)						484905		1679730		14961950	E
								880500		3694020		25500250	I
								1365405		5373750		40482200	T
	WALL-FIRED	F (500-10000+)								1680230	5627520	14849950	E
										3700720	11074680	24175995	I
										5380950	16702200	39025945	T
	TURBO-FIRED	F (100-10000+)						484905		1679730		14981950	E
								880500		3694020		25500250	I
								1365405		5373750		40482200	T

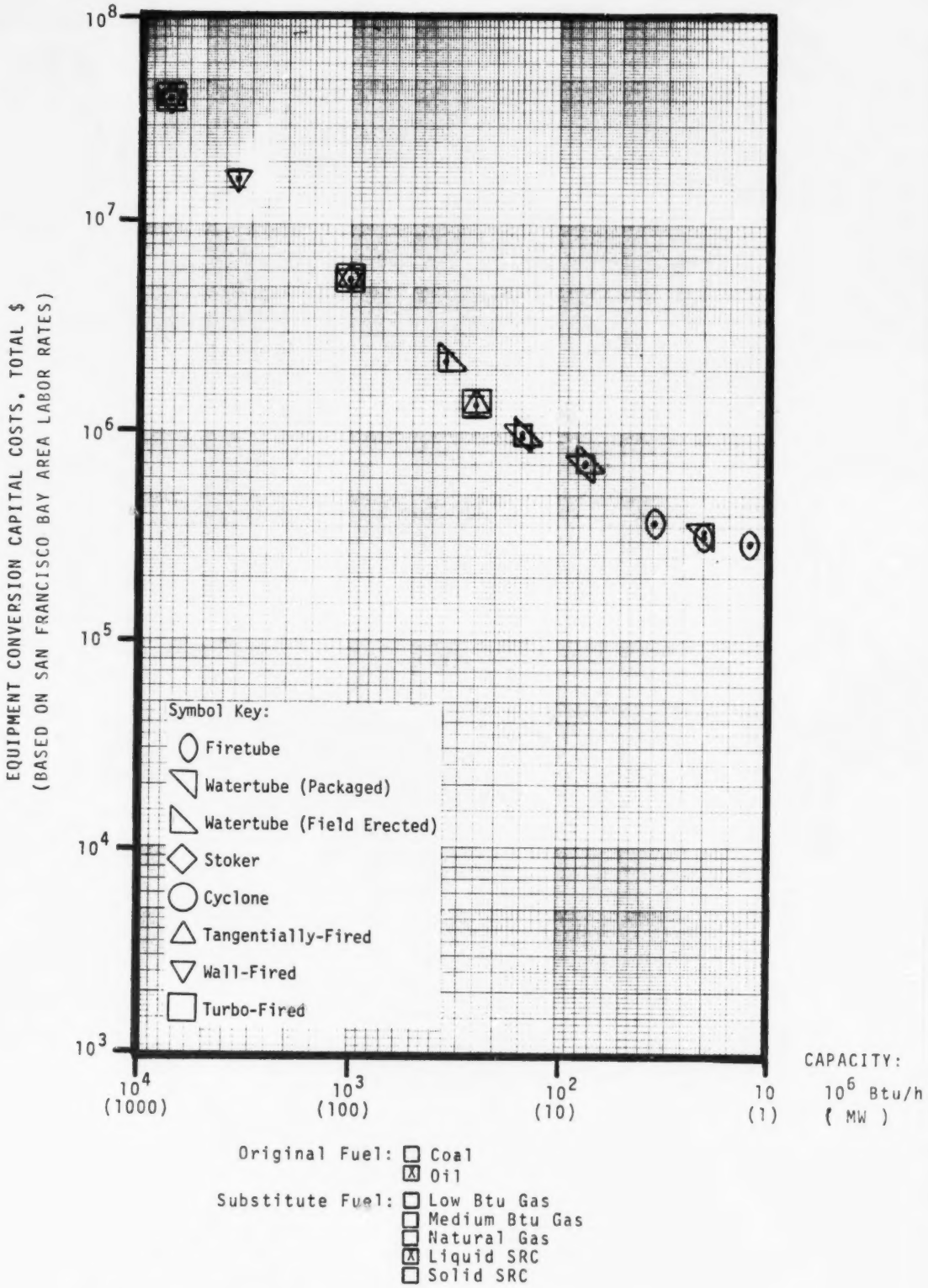

Figure 6-9. Combustion Equipment Conversion Capital Costs (Total $) vs. Boiler Capacity

TABLE 6-15

CONVERSION COST UNCERTAINTY FACTORS

Original Fuel	Substitute Fuel	Boiler Category	Uncertainty	Basis
Coal	Low-, medium-Btu gas and natural gas	Stoker and watertube (F)	±15%	Uncertainty in required number of burners for the furnace and length of fuel piping
Coal and Oil	Low-, medium-Btu gas and natural gas	Cyclone, tangentially-fired, wall-fired, and turbo-fired	+50% -10%	Upper limit due to uncertainty in required number of burners for furnace and length of fuel piping; lower limit based mostly on possible decrease in required piping lengths (also, probability is low that the original number of burners will be reduced upon conversion to a different fuel)
Coal and Oil	Liquid SRC	All boilers	±10%	The uncertainty in the cost of the fuel handling system dominates all other factors
Coal	Solid SRC	All boilers	±25%	Due to uncertainty in: amount of required cooling water, ductwork required to bypass preheater, piping to bring water from source to boiler front, cost of materials for stainless steel nozzle, plus general lack of knowledge of solid SRC's handling and combustion properties
Oil	Low-, medium-Btu gas and natural gas	Firetube	±10%	Uncertainty in piping installation costs
Oil	Low-, medium-Btu gas and natural gas	Watertube (P)	±15%	Uncertainty in required number of burners for the furnace and length of fuel piping

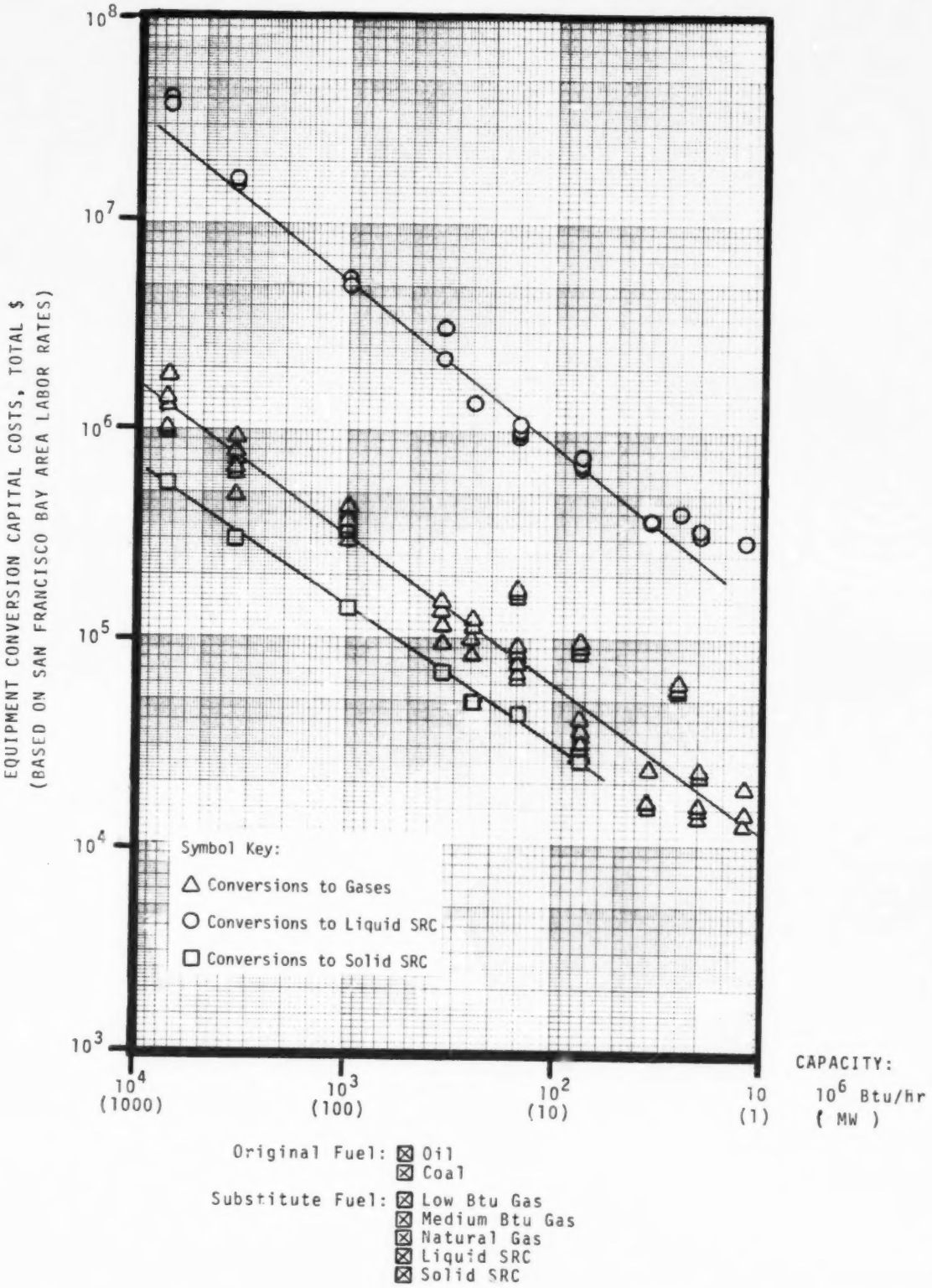

Figure 6-10. Composite of All Conversion Cost Data vs. Capacity

- The differences in conversion costs for the field-erected and packaged watertube boilers are slight. An incrementally higher engineering cost for the latter type accounts for this difference.

Figure 6-10 is the composite of all cost data previously shown in Figures 6-1 through 6-9. Three lines, again appearing to conform to power law functional relationships, have been fared in to illustrate the correspondence between cost and capacity for all boiler types for the three major fuel switching strategies. These are:

- Conversion to Liquid SRC
  Enabling all coal- or oil-fired boiler types to use liquid SRC is clearly the most expensive fuel substitution option. This cost is dominated by the elaborate fuel handling system that is required.
- Conversion to solid SRC
  This appears to be the least expensive strategy for abating SO_x emissions by way of fuel switching. It does, of course, apply only to boilers that were originally burning coal. The low cost reflects the savings realized through the reuse of existing fuel handling and firing equipment.
- Conversion to the Coal-Derived Gases and Natural Gas
  These costs fall between those for liquid and solid SRC. The option for conversion to gas is open for all boiler types firing either original fuel. Due to the data scatter, the straight line in Figure 6-10 representing the costs for this operation is only one of many that could have been drawn in. It serves, however, to identify the overall trend. A more accurate placement of the line can be obtained by performing a regression analysis.

6.3.4 Use of Cost Data for Other Locations

As was mentioned previously, the installation costs associated with each type of conversion were based on San Francisco Bay Area labor rates. Therefore, the total plant investment as shown on the data sheets is specific for that metropolitan area. To determine installation costs for other areas, it will be necessary to modify the Bay Area figures by some labor rate factor.

M. W. Kellogg Co. presented location factors for the major U.S. cities in Reference 6-4. These are repeated in Table 6-16. Adjacent to each of these numbers is a corresponding factor as normalized to the Bay Area figure (1.45). With these factors, the installation cost estimates contained in this report can be used to calculate total equipment conversion capital costs for other major cities.

TABLE 6-16

LOCATION FACTORS FOR MAJOR U.S. CITIES

Location	M. W. Kellogg Location Factor (Reference 6-4)	Location Factor Normalized to San Francisco
Atlanta	1.10	0.76
Baltimore	1.41	0.97
Birmingham	1.16	0.80
Boston	1.23	0.85
Chicago	1.52	1.05
Cincinnati	1.53	1.06
Cleveland	1.86	1.28
Dallas	1.07	0.74
Denver	1.03	0.71
Detroit	1.73	1.19
Kansas City	1.37	0.95
Los Angeles	1.44	0.99
Minneapolis	1.54	1.06
New Orleans	1.16	0.80
New York	2.08	1.43
Philadelphia	1.82	1.25
Pittsburgh	1.52	1.05
St. Louis	2.01	1.39
San Francisco	1.45	1.00
Seattle	1.21	0.83
Houston	1.00	0.69

6.3.5 Proposed Cost Models

Interpolation and regression will allow the formulation of the functional relationships suggested by the correspondences between cost and capacity for each type of fuel-to-fuel conversion for each boiler category, as shown in Figures 6-1 through 6-9. Therefore, the most specific cost models would take the following forms:

$$\text{SRC} \begin{cases} \text{Equipment Cost} = (K_e)\ (\text{Capacity})^{n_e} \\ \text{Installation Cost} = (F)(K_i)\ (\text{Capacity})^{n_i} \end{cases}$$

$$\text{Gas} \begin{cases} \text{Equipment Cost} = (K_e)\ (\text{Capacity})^{n_e}(\text{HHV})^{P_e} \\ \text{Installation Cost} = (F)(K_i)\ (\text{Capacity})^{n_i}(\text{HHV})^{P_i} \end{cases}$$

where

HHV = high heating value for substitute fuel gas (Btu/scf)

F = location factor

and n's, p's and K's are calculated by the regression analysis.

Due to the lack of more than three data points for each boiler type, and the overall scatter of the data, the creation of these elaborate cost models may not be justified. More simplistic cost models can be obtained from the composite of all the data, illustrated previously in Figure 6-10. Thus, the general form of these functions would be the same for the three principal fuel substitution options for all boiler types:

$$\text{Equipment Cost} = (K_e)(\text{Capacity})^{n_e}$$

$$\text{Installation Cost} = (F)(K_i)(\text{Capacity})^{n_i}$$

The total plant investment is the sum of the equipment and installation costs.

SECTION 7

CONCLUSIONS AND RECOMMENDATIONS

The following are this study's major conclusions:

- On the basis of the estimated equipment modification cost data, there appear to be three basic fuel switching options for the abatement of oxides of sulfur emissions from industrial and utility boilers. These include conversions to melted solvent refined coal, solid solvent refined coal, and the gaseous fuels of any heating value.
- Based on the engineering assumptions made during the cost estimation procedure, conversions to hot liquid SRC seem to be the most expensive of the investigated alternatives. The fuel handling system cost is the major portion of the total plant investment. This strategy is open to applicable boiler types firing either oil or coal.
- Converting coal-fired boilers to the use of solid SRC is the least expensive alternative. Considerable cost savings result from the reuse of the existing fuel handling and firing sytems. Modifying oil-fired boilers to enable the use of solid SRC is considered impractical. The costs of such an operation would exceed the costs for converting to liquid SRC.
- Between the costs for converting to SRC in either phase lie those for converting to the gaseous fuels. These costs are generally inversely proportional to the heating value of the substituted gas. This fuel switching option is available for all boiler types firing either oil or coal originally. The sulfur oxide reduction benefit is greater for the gaseous fuels since, unlike SRC, they contain no sulfur.
- There appears to be a correspondence between conversion cost and capacity for the three basic fuel switching options; a power law functional relationship probably best describes this correspondence.

The following are the principal recommendations made in light of the results of this study:

- A regression analysis should be performed for each of the correspondences between conversion cost and boiler capacity for each of the three major fuel substitution options. This procedure will result in the formulation of generalized equipment conversion cost models.
- The results of the ongoing experimental and practical activities in handling and burning solvent refined coal and the lower-Btu gases should be used to periodically update the cost estimations contained in this report.
- The cost estimation methodology used in this study should be employed to evaluate the costs of converting boilers to other coal-derived fuels, especially the products from the more promising coal liquefaction processes.

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APPENDIX A

PROCESSES FOR LOW AND INTERMEDIATE BTU FUEL GAS

(From Reference 4-21 except where noted)

PROCESSES FOR LOW AND INTERMEDIATE BTU FUEL GAS

Developed or Offered by (and Process Name if any)	Process Comments	Status and Remarks
Applied Technology Corp.	Coal is continuously gasified by air (without steam) in a molten-iron bath. Reaction with limestone takes out sulfur.	Tested in pre-pilot reactor equivalent to 10 bl/min of coal. Aiming for funding for bigger unit.
Applied Technology Corp. (Patgas)	Similar to company's Atgas process (see Appendix B) but without shift conversion or methanation.	Gas intended for, e.g., iron and steel industry
Babcock & Wilcox Co.	Coal is entrained in air for feeding to gasifier, which uses no steam. Char is recycled.	Tested in experimental unit.
Bituminous Coal Research, Inc.	Gasification in multiple fluidized beds yields a gas stream free of liquids. Btu content of gas depends on whether air or oxygen is fed.	Construction of 100-lb/h unit to begin at Monroeville, PA, this year.
Columbia University	Coal's carbon reacts with steam in electric arc at about 10,000°C. Depending on reaction and subsequent quench conditions, process can be used to make low- or high-Btu gas.	As of May 1973, had been tested on batch basis at about 30 kw. Sponsored by Consolidated Natural Gas Co.
Combustion Engineering, Inc.	Pulverized coal is entrained in air and steam for feeding to gasifier.	Preliminary tests completed; await funding for 5-ton/h unit.
Davy Powergas, Inc. (Winkler)	Fluidized-bed gasification accommodates wide range of particle sizes. Some installations use oxygen instead of air, to obtain higher-Btu gas.	Developed in Germany; widely commercial in Europe and Asia; no contracts in U.S. yet.

PROCESSES FOR LOW AND INTERMEDIATE BTU FUEL GAS (Continued)

Developed or Offered by (and Process Name if any)	Process Comments	Status and Remarks
Garrett Research & Development Co. (GRD Coal Gasification Process)	Gasifier output of pipline-gas process described in Appendix B is also offered (after cleanup) for industrial fuel, at about 600°F 650 Btu/ft^{3}F).	See Appendix B.
General Electric Co. (Gegas)	Employs a moving fixed bed of coal and ash in gasifier. Under study are: feeding of coal fines by mixing with tar and then extruding; use of solid diluents to increase mass-flow through gasifier; use of liquid membrane for H_2S removal.	Tested at 50-lb/h rate. Seeking partners for erecting a demonstration unit at a utility plant.
Hydrocarbon Research, Inc.	Conical fludized-bed gasifier. High superficial velocity permits bed to operate at above ash softening point (e.g., 2200°F to 2300°F).	Concept developed by Arthur Squires, of City University of New York. HRI proposes a 10-ton/d unit.
Institute of Gas Technology (U-Gas)	Mild air-oxidation pretreats coal to avoid caking and produces a portion of the gas product. Fluidized-bed gasifier includes conical internals; ash is agglomerated within the cones.	Design study underway for pilot plant (10 to 35 tons/h).
M. W. Kellogg Co.	Gasification step similar to that in firm's pipeline-gas process (see Appendix B); but it employs air instead of oxygen, and no steam.	Investigating formation of concortium for demonstration project at a utility plant.
Koppers Co. (Koppers-Totzek)	Oxygen employed instead of air. Gasification occurs at very high temperatures around 3000°F, yielding an effluent free of tars and similar condensables. Raw gas is about 300 Btu/ft^3.	Sixteen commercial plants in Europe and Afica, making ammonia-synthesis gas. U.S. inquiries also involve fuel gas and pipeline gas.

PROCESSES FOR LOW AND INTERMEDIATE BTU FUEL GAS (Concluded)

Developed of Offered by (and Process Name if any)	Process Comments	Status and Remarks
Lurgi Gesellschaft für Wärmeund Chemotechnik mbH.	Gasifier at about 300 psi receives coal through a lock hopper. Revolving grate at bottom removes ash and allows air and steam to enter. Oxygen replaces air to manufacture town gas (or a precursor for pipeline gas; see Appendix B).	Process has been widely used outside U.S. to make town gas, synthesis gas and fuel gas.
North American Rockwell, Corp.	Coal is contacted with air (but no steam) in molten Na_2CO_3, at about 1800°F and 5 to 10 atm. Sulfur and ash removed externally, from a recirculating bleed stream of the salt.	Has been tested (at 1 atm) in 200-lb/h unit. A 5-ton/h pilot plant with Northeast Utilities Service Co. is planned for Norwalk, Conn.
Riley Co.	Low-pressure gasification; fixed bed of coal. Btu content of gas depends on whether air or oxygen is fed.	Fuel-gas manufacturers are offered an updated version of Morgan Construction Co. gasifiers.
U.S. Bureau of Mines	Gasification reactor's stirrer moves horizontally and vertically, providing uniform gasification conditions with caking or noncaking of any size.	Successfully tested at Morgantown, W. VA, in 12-ton/d unit having a 3-ft-dia reactor.
Wellman-Galusha (Reference 4-12)	Atmospheric, fixed-bed process; similar to Lurgi	Unknown
Westinghous Electric, Corp.	Gasifier has fluidized bed of recirculated char. Insensitive to coal's size distribution, caking properties and sulfur content.	A 1200-lb/h pilot plant due onstream at Waltz Mill, PA Commercial unit to be built at a Terre Haute, Ind., utility plant by 1978.
Westinghouse Electric Corp.	Gasifier at around 1850°F produces gas to energize solid-electrolyte fuel cells immersed in gasifier bed itself. Water vapor and carbon dioxide from fuel cell react with coal during gasification.	Concept studied between 1962 and 1970 and found to be attractive; but no active project underway now.
Woodall-Duckham Ltd. (IGI Two-stage Coal-Gasification Process)	Gasifier, operating a 1 atm, is divided into compartments by vertical walls, to aid distribution of rising gas through descending bed of coal.	Developed by Italy's II Gas Integrale in 1940's. Being offered anew by Woodall-Duckham.

APPENDIX B

PROCESSES FOR HIGH BTU PIPELINE GAS (SNG)

(From Reference 4-21)

PROCESSES FOR HIGH BTU PIPELINE GAS (SNG)

Processes Developed With Their Own Technology for Methanation

Developed or Offered by (and Process Name if any)	Process Comments	Status and Remarks
Bituminous Coal Research, Inc. (Bi-Gas)	Gasifier, at 1000 to 1500 psi, has two stages. Char is gasified with oxygen and steam in lower stage; the gas rises, picking up and entraining incoming coal; this stream goes to upper stage, which makes char and enriches the gas. Methanator has fluidized catalyst bed, with imbedded heat-transfer surfaces.	Gasification tested in 100-lb/h continuous unit; methanation likewise sucessfully tested. A 5-ton/h pilot plant for overall process being built at Homer City, PA.
Columbia University	Coal's carbon reacts with steam in electric arc at about 10,000°C. Proper reaction and quench conditions enable production of SNG without additional methanation step.	As of May 1973, had been tested on batch basis at about 30 kw.
Institue of Gas Technology (Hygas)	After pretreatment by air oxidation or by dilution with char, coal is oil-slurried and fed to top of 1000 - 1500 psi two-stage hydrogasifier, while mixture of steam and hydrogen (generated externally, from leaving hydrogasification) enters at the bottom. Heat in gasifier is supplied by carbon-hydrogen reaction. Methanator downstream uses multiple packed-catalyst-bed reactors.	Three-ton/h pilot plant compleated at Chicago in 1971 has operated on lignite, with hydrogen produced from char electrothermally. Now, IGT will run caking bituminous coal, and produce hydrogen via oxygen-combustion as source of heat.
Lurgi Gesellschaft für Wärme- und Chemotechnik mbH. (Lurgi Pressure Gasification)	In pipeline-gas projects, gasifier with lock hopper and grate (see Appendix A) employs oxygen for gasification, producing a raw gas of about 400 Btu/ft^3. A heterogeneous nickel catalyst is used in the downstream methanation step.	Gasification well established (see Appendix A). Methanation being groomed in demonstration plants. First SNG-from-coal plants in U.S. will use Lurgi technology.

PROCESSES FOR HIGH BTU PIPELINE GAS (SNG) (Continued)

Processes Developed With Their Own Technology for Methanation (Concluded)

Developed or Offered by (and Process Name if any)	Process Comments	Status and Remarks
Stone & Webster Engineering Corp. (Solution/Gasification)	Coal is slurried in a solvent; then a two-step treatment with hydrogen solubilizes the coal and produces pipeline-quality gas without an explicit methanation step. Process does not entail oxygen or steam.	Tested on bench scale. Under new joint venture with General Atomic, nuclear reactors will provide heat for hydrogen generation. Demonstration plant planned.
U.S. Bureau of Mines (Synthane)	Coal is pretreated with steam and oxygen in fluidized-bed reactor that is integral part of gasification system. The system operates at high pressures (e.g., 1000 psi). Of methane contained in final gas, 60 percent is made during gasification step. Two variants of downstream methanation with Raney nickel catalyst are under study.	Tested in continuous unit rated at 10 to 20 lb/h. A 75-ton/d pilot plant due completed at Bruceton, PA, in August 1974.

Processes That Will be Combined with "Outside" Methanation Technology

Applied Technology Corp.	Coal is injected into 2500°F molten-iron bath; reaction with steam and oxygen produces sulfur-free gas for shift conversion and methanation. Sulfur removed as slag by limestone addition.	Gasification step has been tested in 2-ft-dia. reactor, equivalent to 10 lb/min of coal. Company seeks funds to build 15-ton/h unit.
Babcock & Wilcox Co.	Entrained-coal gasifier; char recycled. Methane content of gasifier output can be regulated by selecting pressure and temperature.	Technology commercial in 1950's for making synthesis gas. Now soliciting cutomers for fuel production (including SNG) as well.
Babcock & Wilcox Co.	Gasifier employs sulfur dioxide instead of oxygen for blowing.	Conceptual. Seeking Funds for testing.

PROCESSES FOR HIGH BTU PIPELINE GAS (SNG) (Continued)

Processes That Will be Combined with "Outside" Methanation Technology (Continued)

Developed or Offered by (and Process Name if any)	Process Comments	Status and Remarks
Cogas Development Co. (Cogas)	Multistage pyrolysis of coal yields gas, oil and char. More gas comes from reacting char with steam, at under 100 psi. Heat for gasification supplied by burning some char in air, in a combustor external to the gasifier. No oxygen needed.	Pyrolysis step demonstrated in COED-Process work of FMC Corp., one of the partners in Cogas Development Co. Two pilot plants will test char-gasification step.
Consolidation Coal Co. (CO_2 Acceptor)	Lignite is gasified with steam in presence of hot, calcined dolomite. This reacts exothermally with the gasification-generated carbon dioxide, removing it while providing heat for gasification. Dolomite regenerated by heating.	Runs have been made in a 30-ton/d pilot plant completed in South Dakota in 1972.
Davy Powergas, Inc. (Winkler)	Oxygen-feeding version of process outlined in Appendix A serves as gasification step to precede shift conversion, purification, and methanation.	Developed in Germany; widely commercial in Europe and Asia; no U.S. contracts yet.
Exxon Corp.	Air burns char outside of gasifier, to provide heat for gasification reactions involving steam. System does not require oxygen.	Tested in 1/2-ton/d unit at Baytown, Tex. Design of proposed 500-ton/d plant nearly completed.
Garrett Research & Development Co. (GRD Coal Gasification Process)	A low-pressure (30 to 50 psi) step pyrolyzes coal quickly in the presence of some steam and recycled gas. The pyrolyzer also receives partially burned char (produced externally by air combustion), which supplies the needed heat.	Tested in a 50-lb/h unit (a highly similar liquefaction process has been tested in a 300-lb unit). Now seeking support for a 250-ton/d pilot plant.

PROCESSES FOR HIGH BTU PIPELINE GAS (SNG) (Concluded)

Processes That Will be Combined with "Outside" Methanation Technology (Concluded)

Developed or Offered by (and Process Name if any)	Process Comments	Status and Remarks
M. W. Kellogg Co.	Coal is contacted with oxygen and steam in a molten-sodium-carbonate bath at about 1700°F. and 1200 psi. The salt serves as catalyst and heat-transfer agent; all operations involving salt take place in the one vessel. Raw gas from gasification is tar-free. Of methane in the final gas, 55 percent to 60 percent is made during this gasification step.	Process development, underway for several years, has included studies in a 5-1/4-in-dia. reactor. Next step will employ a 30-in reactor. Funding sought for building a large continuous pilot plant.
Koppers Co. (Koppers-Totzek)	Effluent from gasification described in Appendix A is suitable for shift conversion, and methanation.	Sixteen commercial plants in Europe and Africa, making ammonia-syntesis gas.
Union Carbide/Battelle/Chemico	Two fluidized-bed systems, a combustor and a gasifier, are linked by an agglomerated-ash circuit that transfers heat. Gasifier, at 1800°f and 250-350 psi, is fed coal and steam; the combustor is fed char and air. No oxygen required.	Components of process tested during 1960's by Union Carbide and Battelle. Chemico completing design, for Battelle, for 25-ton/d pilot unit.
U.S. Bureau of Mines (Hydrane)	In a first, "dilute" stage, coal particles are heated through their plastic-transition temperature range in a stream of hydrogen and methane from fluidized-bed second stage. Devolatilized coal, meanwhile, falls into second stage, where it contacts hydrogen gernerated externally from char, steam and oxygen. Gas leaving dilute stage, at 2000 psi, is 75 percent or more methane.	The two stages have been tested separately at Bruceton, PA. A pilot unit to demonstrate them together has just been built but is not likely to start up during this fiscal year.

APPENDIX C

BULK CONVERSION COST DATA

BOILER CATEGORY: FIRETUBE 8-8-74

ORIGINAL FUEL: Oil SUBSTITUTE FUEL: LOW BTU GAS SHT 1 of 15

			1		2		3		4		5		6	
			9 = 12x10⁶				20x10⁶				35x10⁶			
		BURNER & WINDBOX - E	EQUIP		INSTALL		EQUIP		INSTALL		EQUIP		INST.	
1	1	BURNER ASS'Y	$ 2000.00	4	100.00	8	2400.00	6	150.00	8	2400.00	6	150.00	1
2		ADAPTOR PLATE	500.00	8	200.00		500.00	12	300.00		500.00		300.00	2
3		GAS ELECTRIC PILOT	400.00	1	25.00		400.00		25.00		400.00	1	25.00	3
4														4
5		BURNER MANAGEMENT - M												5
6		LIMITS: H.G.P. - F	120.00	2	50.00		120.00		50.00		120.00		50.00	6
7		L.G.P. - F	120.00	2	50.00		120.00		50.00		120.00		50.00	7
8														8
9														9
10		BURNER FUEL PIPING												10
11	1	PILOT TRAIN - FA	250.00		—		—		—		—		—	11
12	1	MAIN GAS - FA	5000.00		1000.00		6000.00		1500.00		7500.00		2000.00	12
13	1	SUPPLY PIPING	610.00	4	100.00		610.00		1100.00		610.00		1100.00	13
14														14
15		INSTRUMENT - CONTROL CNTR.												15
16	2	PRESS GAGES - F	75.00		INCL		75.00		INCL		75.00		—	16
17		CONTROL VALVE DAMPER	—	4	100.00									17
18														18
19														19
20		FAILS - NO CHANGES	—		—		—		—		—		—	20
21														21
22														22
23														23
24														24
25		FURNACE - BOILER MOD	100.00	4	100.00		200.00	4	200.00		200.00		200.00	25
26			$ 9175.00		$ 5725.00		$ 10,625.00		$ 6375.00		$ 12,125.00		6875.00	26
27														27
28														28
29														29
30		MISC. SCHEDULE												30
31		SIGN	2450.00		—		2550.00		—		2950.00		—	31
32		STACK - U.P.	—		1250.00		—		1250.00		—		1250.00	32
33		INSTALL. SUPER.	—		660.00		—		650.00		—		700.00	33
34														34
35														35
36			$ 11425.00		$ 7575.00		13175.00		8275.00		14975.00		8825.00	36
37														37
38														38
39														39
40														40

4806 - Buff
4806 - Blue
4806 - Green

BOILER CATEGORY: FIRE TUBE — SHT 2 of 15

ORIG. FUEL: OIL — SUBSTITUTE FUEL: MBG — 8-12-74

	12 MKB		20 MKB		35 MKB	
BURNER & WINDBOX	EQUIP	I	E	I	E	I
1 BURNER ASS'Y	1250	100	1500	150	1750	200
1 ADJUSTOR PLATE	500	200	500	250	500	300
1 GAS ELECTRIC PILOT	300	25	300	25	300	25
BURNER MANAGEMENT						
1 LIMITS: HG.P.	120	50	120	50	120	50
1 L.G.P.	120	50	120	50	120	50
BURNER FUEL PIPING						
1 PILOT TRAIN	250	—	250	—	250	—
1 MAIN GAS TRAIN	2500	INCL	3250	INCL	4000	INCL
1 SUPPLY PIPING	610	4100	610	4100	610	4100
INSTRUMENT - COMB. CONTR.						
2 PRESS GAGES - E	75	INCL	75	INCL	75	INCL
CONTROL WIR. DIAG.	—	100	—	100	—	100
FAN NO CHANGE	—	—	—	—	—	—
FURNACE - BOILER MOD	100	100	200	200	300	300
	5825	4725	6925	4925	7925	5025
MISC SERVICES						
ERECT	1600	—	1800	—	1950	—
START-UP	—	1250	—	1250	—	1250
SUPER	—	500	—	500	—	500
	7425	6475	8725	6625	9875	6725

BOILER CATEGORY : FIRETUBE
ORIG. FUEL : OIL SUBSTITUTE FUEL : NAT. GAS

SHT 3 of 15
8-13-74

		1	2	3	4	5	6
		12 MKB		20 MKB		35 MKB	
	BURNER & WINDBOX	E	I	E	I	E	I
1	1 BURNER ASS'Y	1000	100	1200	150	1400	200
2	1 ADAPTOR PLATE	400	200	400	250	400	300
3	1 GAS ELECTRIC	300	25	300	25	300	25
4							
5	BURNER MANAGEMENT						
6	LIMITS H.G.P.	120	50	120	50	120	50
7	L.G.P.	120	50	120	50	120	50
8							
9							
10	BURNER PIPING						
11	PILOT TRAIN	250	INCL	250	INCL	250	INCL
12	MAIN GAS TRAIN	1800	INCL	2500	INCL	2500	INCL
13	SUPPLY PIPING	610	4100	610	4100	610	4100
14							
15	INSTRUMENT - CONTR. CONTR.						
16	2 PRESS. GAGES - E	75	INCL	75	INCL	75	INCL
17	CONTROL VAL. DRAWER	—	100	—	100	—	100
18							
19							
20	FAN - NO CHANGE	—	—	—	—	—	—
21							
22							
23							
24							
25	FURNACE - BOILER MOD	—	—	—	—	—	—
26		4675	4625	5575	4725	6775	4625
27							
28							
29							
30	MISC SERVICES						
31	ENGR	1975	—	1550	—	1750	—
32	START-UP	—	1250	—	1250	—	1250
33	SUPERV	—	475	—	475	—	500
34							
35							
36	TOTAL	6075	6350	7125	6450	8525	6375
37							
38							
39							
40							

4806 - Buff
5806 - Blue
8806 - Green

BOILER CATEGORY : FIRETUBE — SHT 4 of 15

ORIG. FUEL: OIL — SUBSTITUTE FUEL : SRC — 8-13-70

	1	2	3	4	5	6
	12 MKB		20 MKB		35 MKB	
BURNER & WINDBOX	E	I	E	I	E	I
1 BURNER ASSY	900	160	900	160	1100	160
1 REGISTER PLATE-SCREW	350	160	350	160	520	160
1 GAS ELECTRIC PILOT	100	20	100	20	100	20
1 SPARE GUN	250	—	250	—	300	—
BOILER MANAGEMENT						
1 H.R.P.	200	60	200	60	200	60
1 L.C.F.	50	80	50	80	50	80
BURNER FUEL PIPING						
1 PILOT TRAIN	100	60	100	60	100	60
1 MAIN GAS TRAIN	1000	160	1000	160	1250	200
1 SPARE PIPING	92,670	149368	98500	163440	106730	199340
1 STM TRAIN	350	120	350	120	400	160
TESTPOINT-COND. CONN.						
2 PRESS-GAGE	600	80	600	80	600	80
CONTROL VAL. PIPE	—	—	—	—	—	—
FAN - NO CHANGE						
FURNACE-BOILER MTG.	1250	200	1250	200	1250	200
	[illegible]	[illegible]	103750	184200	114500	200962
	97,820	150256				
	96000	150,000	104,000	184,000	115,000	201,000
MISC SERVICES						
ENGR	25,000		30,000		30,000	
START-UP		10,000		10,000		10,000
SUPER.		15,000		18,000		20,000
	$123,000	$175000	$134,000	$212,000	$145,000	$231,000

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COSTS FOR CONVERTING ALL BOILER TYPES FROM COAL TO SOLID SRC (#)

CAPACITY (10^6 Btu/hr)	75	150	250	350	1000	3500	7500
NO. OF BURNERS	1	2	2	4	8	28	60
COOLING WATER TUBES	3500	6000	6000	10000	20000	50000	90000
COOLING WATER HDR	0	500	500	1000	2000	5000	9000
COOLING WATER TANK AND HEAT EXCHANGER	2500	3500	3500	5000	10000	25000	45000
COOLING WATER PUMP	750	1000	1000	1500	2500	5000	9000
CONNECTING PIPES & VALVES	1750	2500	2500	3500	6000	15000	25000
AIR PREHEATER BYPASS	3325	10000	16000	20800	58240	122000	210000
ENGINEERING	6000	8000	8000	10000	15000	20000	30000
INSTALLATION	7500	10000	10000	15000	25000	50000	80000
SUPERVISION	1000	1500	1500	2000	3000	5000	8000
START-UP SERVICE	500	800	800	1000	2000	3000	5000
TOTAL EQUIPMENT COST	16825	28000	31000	43400	86740	186000	345000
TOTAL INTALLATION COST	10000	15800	18800	26400	56000	114000	215000
TOTAL PLANT INVESTMENT	26825	43800	49800	69800	142740	300000	560000

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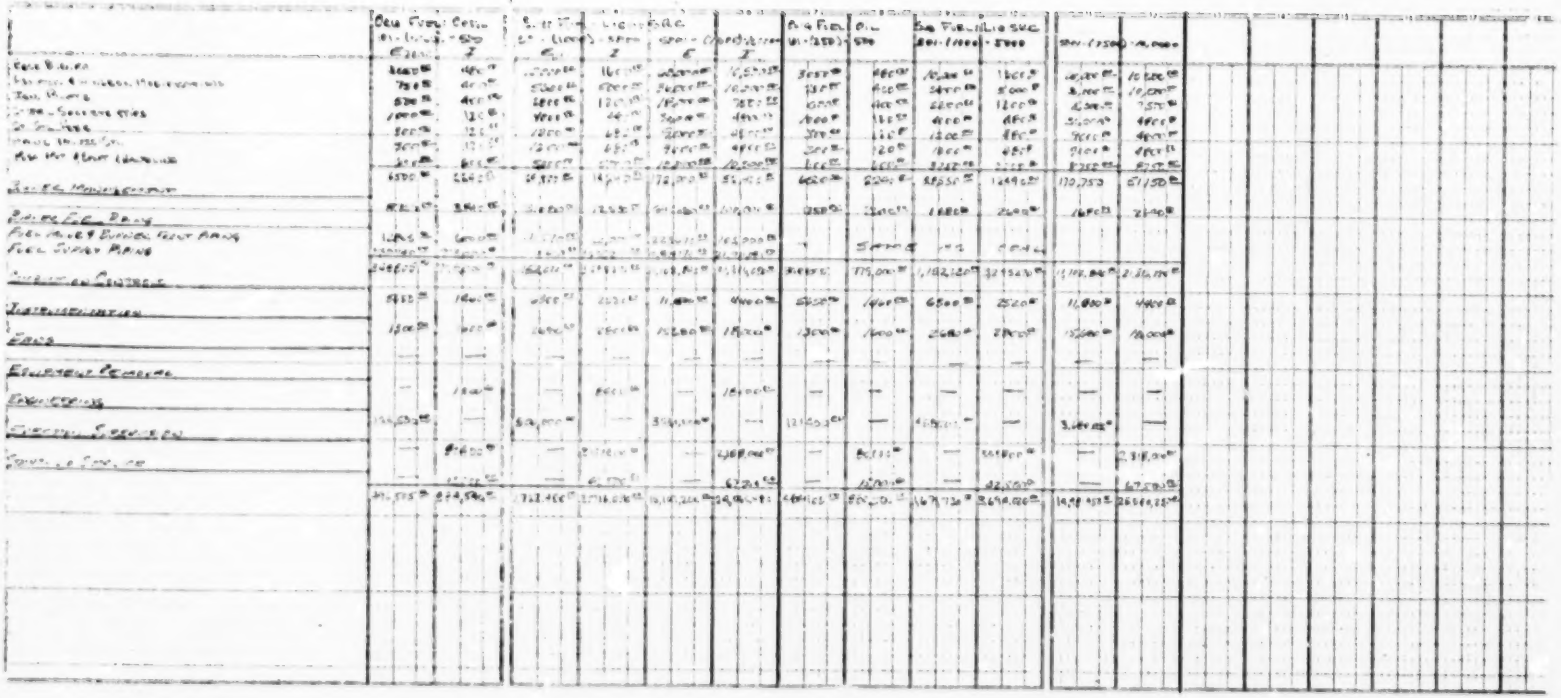
Boiler Cat. No.: 2800 # Cyclone

	Boiler Only 15-150 MW		Sub Total Boiler 51-150 MW		Sub Total Boiler 101-150 MW		Sub Total Boiler 151-250 MW		Sub Total Boiler 251-500 MW		Sub Total Boiler 501-1000 MW	
	E	I	E	I	E	I	E	I	E	I	E	I
Boilers (2 required)	500	700	1000	1400	1400	2000	4600	5000	8000	8000	14,000	14,000
Gas Ties	1500	350	2200	1600	2800	1400	—	—	—	—	—	—
Boiler Feed Pumps & Service (1-100% spare)	900	100	1800	900	1750	1200	3200	1400	4600	2000	12,000	16,000
Pilots	100	100	180	100	200	100	750	400	2800	1200	5,000	7,000
Trailer Tube	1500	600	2200	1400	4000	1600	—	—	—	—	—	—
Insulated Walls	—	—	—	—	4000	—	—	—	—	—	—	—
Mod. Membrane	800	—	4000	—	7300	—	7200	—	14,000	5000	24,000	9200
Soot Blowers & Sys. Yds	250	400	500	600	700	900	1000	500	2200	800	5200	6500
Sky Houses	100	40	150	60	400	150	800	300	800	300	2200	800
Hand Valves (2 per Boiler)	150	90	150	60	200	80	200	80	200	80	400	150
Boiler Maintenance 3%	4850	1800	7000	2600	10,500	4200	16,400	6200	32,000	12,000	48,000	60,000
Burner Fuel Piping	3000	2500	3700	2700	5,200	3900	8,000	5800	11,000	8,000	24,000	30,000
Fuel Valve (Gas) Steam Piping	3100	1800	4200	2200	6,000	3,200	12,000	6,000	24,000	12,000	48,000	60,000
Fuel Skid + Piping	11,850	7,900	15,900	10,600	22,700	15,100	35,200	23,400	67,800	45,200	135,000	90,000
Combustion Controls	3,185	2,150	4,657	3,500	6,700	5,025	10,800	8,100	15,420	11,565	30,840	23,130
Instrumentation	2000	800	2600	1100	2800	1200	5450	1460	6200	2620	11,000	4400
Panel, MCC	825	550	825	550	1200	800	1300	1800	2680	2800	5,200	10,000
Air Compressor	2000	400	3000	900	5700	1500	—	—	—	—	—	—
Equipment Removal, Freight & Misc.	—	2,500	—	3,000	—	3,000	—	—	—	—	—	—
Engineering	5,100	—	6,500	—	9,500	—	12,500	—	16,500	—	5,460,000	—
Erection Supervision	—	2,500	—	3,000	—	5,400	—	6,300	—	14,000	—	28,000
Start-up Service	—	700	—	1,000	—	1,700	—	1,800	—	4,200	—	6,200
	1,419,36	1,918,15	3,125,25	4,468,85	4,179,50	6,241,70	6,844,60	9,761,30	1,668,60	3,326,70	4,128,06	5,914,40

C-9

EQUIPMENT CATEGORY: TANGENT PLAN SECTION FIELD



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	Orig Fuel Cor. 501-(1000)-1000 E	Orig Fuel Cor. 501-(1000)-1000 I	Sub Fuel Lo Src 1001-(3500)-5700 E	Sub Fuel Lo Src 1001-(3500)-5700 I	Sub Fuel Lo Src 501-(1000)-1000 E	Sub Fuel Lo Src 501-(1000)-1000 J	Cla Fuel 01 501-(1000)-1000 C	Cla Fuel 01 501-(1000)-1000 I	Sub Fuel Lo 1001-(3500)-5700 C	Sub Fuel Lo 1001-(3500)-5700 J	Src 501-(1000)-1000 C	Src 501-(1000)-1000 I
Fuse Bldg	10,000	18,000	30,000	17,640	50,000	11,550	10,000	14,000	51,000	53,460	10,000	16,120
Burner Plate & Orifice Modifications	5,600	5,000	16,500	7,200	33,000	15,500	5,600	5,000	16,800	7,200	5,500	5,000
Fan Plates	5,600	1,200	9,100	4,400	18,000	7,200	2,000	1,200	9,100	4,400	18,000	7,200
Fuel Sublevel Tk	7,000	4,800	14,000	21,000	30,000	46,200	4,000	4,800	14,000	21,000	30,000	40,000
Insta Hose	1,200	4,800	4,200	21,000	9,000	42,000	1,200	4,800	4,200	21,000	9,000	42,000
Valves-Stl	1,200	4,800	4,200	21,000	9,000	42,000	1,200	4,800	4,200	21,000	9,000	42,000
Misc Mech & Const Mat	6,000	—	7,000	—	18,000	—	3,700	—	6,000	—	2,750	—
Misc Handling	—	5,000	—	3,000	—	10,000	—	3,000	—	6,000	—	5,000
E-B	29,000	14,240	85,000	3,200	169,000	51,200	26,500	12,990	89,000	29,000	67,700	51,750
Burner Fuel Piping	2,600	2,500	11,600	48,000	29,000	104,000	600	2,600	4,000	14,000	600	2,600
Burner Valves & Controllers, Piping Fuel & Mfg Piping	4,500	20,000	10,000	52,000	22,500	165,000	4,500	20,000	10,000	56,000	22,500	105,000
	12,000	27,000	39,000	69,000	84,000	215,000	11,000	35,000	38,000	70,000	23,000	217,000
	53,000	74,000	209,000	274,000	311,000	581,000	44,000	82,000	204,000	274,000	131,000	715,000
Insulation Casing	68,000	7,000	8,000	36,000	11,000	44,000	6,000	2,500	8,000	36,000	11,000	44,000
Structural Supports	2,000	2,800	7,000	5,000	15,000	18,000	2,000	2,800	7,000	8,000	15,000	18,000
Fans	—	—	—	—	—	—	—	—	—	—	—	—
Equipment Removal	—	8,000	—	12,000	—	18,000	—	8,000	—	12,000	—	18,000
Engineering	425,000	—	122,000	—	3,000,000	—	49,000	—	1,228,000	—	3,000,000	—
Erection Supervision	—	33,000	—	8,000	—	2,000,000	—	33,000	—	1,007,000	—	1,000,000
Start-up Service	—	4,000	—	8,000	—	10,000	—	4,000	—	12,000	—	10,000
	574,000	157,000	500,000	1,112,000	5,000,000	22,000,000	168,000	270,000	1,627,000	1,638,000	14,000,000	24,000,000

BOILER COMPANY, TANGENTIALLY FIRED & TWIN FIRED

MAN FORM CODE: 07.21

CURVE CODE FIGS.	101-(1000) E (1)	501-500 I	1001-(2000) E (2)	501-5000 J	5001-(7500) E (3)	10,001-15,000 I	101-(2500) E (4)	501-5000 I	101-(2500) E (5)	501-5000 I	5001-(7500) E (6)	10,001-15,000 I	101-(2500) E (7)	501-5000 I	101-(2500) E (8)	501-5000 I	5001-(7500) E (9)	10,001-15,000 I
BASE OF GAS HOPPER & SLAG TANK:	2,000	600	21,000	1200	57,000	2,000	2500	800	14,000	1300	36,000	2,000	16,000	2,000	7,000	600	10,000	1,000
BUSTLE PLATES & SLINGER MEMBERS	1,000	800	4,000	1,600	8,000	4,000	1,000	1,600	5,000	1,600	12,000	4,000	9,000	2,000	2,000	800	5,000	1,000
PLATES	600	320	2,400	1,200	18,000	5,760	700	320	1,800	1,000	5,000	1,600	12,000	4,000	500	200	1,000	400
MISC MAT	2,000	2,000	2,000	1,000	15,000	7,000	1,000	1,000	3,000	1,200	10,000	4,000	11,000	9,000	200	150	200	1,000
Z 1-4	10,600	12,720	30,400	4,800	100,500	28,760	5,200	1,920	21,800	4,500	63,000	11,600	48,000	17,000	9,200	1,750	16,200	3,400
BURNER WINDBOX/ECONOMIZER:																		
AREA OF NEW ENCLOSURE (EXCEPT ON FIRST PASS <75,000 BTU/HR/SQ FT)	7,000	1,200	30,000	12,000	244,000	60,000	7,000	1,200	30,000	12,000	240,000	60,000	30,000	12,000	7,000	1,200	30,000	12,000
LINER HGT. OF FD PASS (0.75 FT. > 25 < 100,000)	800	320	2,000	720	3,600	720	800	320	2,000	720	6,000	1,200	2,000	720	800	320	2,000	720
	8,800	1,520	32,000	12,720	247,600	60,720	7,800	1,520	32,000	12,720	246,000	61,200	32,000	12,720	7,800	1,520	32,000	12,720
PRESSURE PART PIPING:																		
PLOT GAS TRAIN	1,200	300	4,600	1,200	24,000	12,000	500	300	4,600	4,000	24,000	22,000	24,000	22,000	500	300	4,600	4,000
MAIN GAS TRAIN	17,000	4,000	64,000	16,000	240,000	60,000	15,000	4,000	30,000	20,000	240,000	90,000	192,000	90,000	17,000	4,000	64,000	16,000
SUPPLY PIPING	5,000	2,000	25,000	6,000	60,000	20,000	5,000	2,000	25,000	10,000	60,000	30,000	60,000	30,000	5,000	2,000	25,000	10,000
	23,200	6,300	93,000	23,200	324,000	92,000	20,500	6,300	59,600	34,000	324,000	142,000	276,000	142,000	22,500	6,300	93,000	30,000
ADDITIONAL CRITERIA:																		
TOTAL LOW REFRACTORY FEED - CAST IN (RECORD BOX)	5,500	2,100	18,000	4,000	117,000	48,000	6,000	2,400	18,000	8,000	72,000	40,000	18,000	6,000	4,000	1,400	5,500	2,200	12,000	4,000
CASTABLE OR GUNNITE:																		
REFRACTORY (WEIGHTS)	1,600	800	6,000	3,000	12,000	6,000	1,600	800	4,000	3,000	12,000	6,000	12,000	4,000	1,600	800	6,000	3,000	12,000	Consult
LAGS:																		
F. D.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
I. D.	2,000	1,000	7,000	3,000	21,000	9,000	2,000	1,000	7,000	3,000	21,000	9,000	7,000	2,000	—	—	—	—
	5,600	1,800	13,000	3,000	33,000	15,000	3,600	1,800	11,000	6,000	33,000	15,000	19,000	6,000	—	—	—	—
EQUIPMENT REMOVAL:	—	1,800	—	4,000	—	12,000	—	1,800	—	6,000	—	18,000	—	6,000	—	1,800	—	6,000
FURNISH SCAFFOLD MAT:	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ENGINEERING:	1,800	—	6,000	—	18,000	—	1,200	—	3,000	—	9,000	—	12,000	—	1,200	—	3,000	—
ERECTION SUPERVISION:	—	6,000	—	24,000	—	72,000	—	5,000	—	15,000	—	45,000	—	21,000	—	5,000	—	15,000
SHOP ASSEMBLY:	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Z 5, 9, 10, 19, 20, 22, 23, 27, 28, 31, 32	59,000	69,000	204,000	64,000	1,000,000	398,000	54,000	64,000	143,000	216,000	1,000,000	1,000,000	842,000	561,000	42,000	28,000	147,000	267,000
FIELD FEED	47,000	69,000	169,000	44,000	1,000,000	398,000	41,000	61,000	120,000	111,000	1,000,000	1,000,000	529,000	449,000	28,000	22,000	94,000	267,000

C-12

BOILER CATEGORY: DETAILED (F)

	Oil Fired 51-(75)-100 E	Oil Fired 51-(75)-100 I	Sub. Fired - Lig. Coal 101-(125)-250 E	Sub. Fired - Lig. Coal 101-(125)-250 I	251-(300)-500 E	251-(300)-500 I	Dom. Fuel - Coal 51-(75)-100 E	Dom. Fuel - Coal 51-(75)-100 I	Sub. Fuel - Solid 101-(125)-250 E	Sub. Fuel - Solid 101-(125)-250 I	H2C 251-(300)-500 E	H2C 251-(300)-500 I	Oil Fired 51-(75)-100 E	Oil Fired 51-(75)-100 I	Sub. Fuel - Lig. Coal 101-(125)-250 E	Sub. Fuel - Lig. Coal 101-(125)-250 I	Sub. Fuel - Lig. Coal 251-(300)-500 E	Sub. Fuel - Lig. Coal 251-(300)-500 I
Boiler Plant (Less Stack) & Aux	17100	8100	36825	48675	57900	69525												
Deliver Plates	400	600	750	4000	1500	7000												
Ducts	300	600	525	4000	1800	7000												
Steel Supports, Platforms etc	250	400	450	1260	1000	2400												
Steel Hoppers	450	300	900	1260	1800	2400												
Misc. Steel Items	150	300	300	1260	600	2400												
Erection Supervision	9250	1160	5960	1690	11400	2260							5700	1160	5700	1690	11400	2260
Boiler Foundations	3125	2160	8750	12600	12500	25200							1250	2160	1250	2300	2500	4320
Boiler Vaults & Structural Steel	4675	2000	11950	5000	23900	10000							935	400	1150	4000	2300	8000
Flue Gas Ducts	17000	7200	43400	18000	86800	36000							3400	1440	4340	18000	8680	36000
Structural Steel	336,325	358,886	277,186	351,932	616,570	1,358,720							21,495	22,956	27,718	35,193	61,657	135,872
Insulation & Lagging	2000	800	2000	1200	3200	1800							200	80	200	120	320	180
Painting	825	800	1200	1600	3300	3500							82	80	120	160	330	350
Engineering	40,000	—	40,000	—	200,000	—							4,000	—	8,000	—	20,000	—
Erection Supervision	—	51,670	—	54,200	—	54,200							—	5,540	—	5,540	—	5,540
Start-up	—	12,000	—	12,000	—	12,000							—	1,200	—	1,200	—	1,200
	291,615	414,326	384,916	499,255	723,170	1,431,560							39,015	41,740	58,635	57,195	110,460	144,870

For, alternative packaged boilers, (oil fired) add extra engineering cost, obtain as ....

29,015	41,740	58,635	57,195	

BOILER CATEGORY: WATERTUBE (F)

SERVICE: FUEL OIL

ITEM	LOW BTU GAS 51-(75)-100 E	LOW BTU GAS 51-(75)-100 I	LOW BTU GAS 101-(150)-250 E	LOW BTU GAS 101-(150)-250 I	251-(375)-500 E	251-(375)-500 I	MED. BTU GAS 51-(75)-100 E	MED. BTU GAS 51-(75)-100 I	MED. BTU GAS 101-(150)-250 E	MED. BTU GAS 101-(150)-250 I	GAS 251-(360)-350 E	GAS 251-(360)-350 I	AIR 51-(75)-100 E	AIR 51-(75)-100 J	GAS 101-(150)-250 E	GAS 101-(150)-250 I	GAS 251-(375)-350 A	GAS 251-(375)-350 F
BASE $ FOR WATER SIDE WORK	2000	160	2600	320	7500	480	1600	120	2400	240	8640	360	1200	120	1800	240	9000	360
PIPING	800	480	800	720	1800	1200	800	400	800	800	17280	960	800	400	720	960	1200	960
PUMP, GAS TO FIRE	400	160	960	240	1800	480	800	160	800	240	17280	960	1000	160	720	240	1200	960
MISC. MAT'L & CONT.	800	160	800	320	1800	480	800	160	1600	320	8640	480	800	400	720	480	1200	960
Z1-4	3952	900	5160	1560	13,200	2640	3200	780	5600	1480	51,840	2160	3800	1080	3250	1920	5700	3240
DIESEL MAINSTREET																		
LUBE: ENGINE OR HYD. SYSTEM LUBE OIL	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
LUBE: WORM GEAR	560	320	800	320	1600	320	800	320	1600	320	800	320	800	320	800	320	800	320
	800	480	800	480	800	480	800	480	800	480	800	480	800	480	800	480	800	480
DIESEL FUEL PIPING																		
PILOT GAS	110	480	320	960	1280	2880	110	480	320	960	1190	2880	110	480	320	960	640	2240
MAIN GAS	3150	1600	16950	4800	36000	14400	2520	1120	14425	4200	22815	7200	1320	880	5770	3000	9580	6000
SUPPLY PILOT	2240	875	3300	2400	5320	37,350	1960	8550	3300	24750	5880	37,350	1940	8550	5300	24750	5870	52,350
MANUAL MAIN	—	—	320	2400	700	2400	—	—	400	2400	880	2400	—	—	400	1200	600	2400
	6000	10,000	20,810	21,200	37,620	57,730	4530	10,150	18,825	30,255	36,160	44,280	3220	9910	9450	30,210	16,520	60,350
INSULATION & CONTROLS	2700	1080	2850	1440	5250	1360	1900	760	2650	1060	3100	1200	1300	520	2850	960	2850	1440
INSTRUMENTATION	1160	880	1925	1840	5275	1360	1100	880	1425	1040	5275	1360	1100	880	1925	1040	5275	1840
FANS & DUCTWORK	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
FD	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ID																		
EQUIPMENT REMOVAL	—	200	—	800	—	1600	—	200	—	800	—	1600	—	200	—	800	—	1600
PIPING MOD.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ENGINEERING	3600	—	8200	—	12,100	—	3200	—	8200	—	10,300	—	2800	—	6400	—	8400	—
ERECTION SUPERVISION	—	1340	—	3855	—	9525	—	1925	—	5750	—	5360	—	1250	—	5470	—	5730
START-UP SERVICE	—	1000	—	1720	—	2000	—	1600	—	1750	—	5800	—	1000	—	1720	—	2200
For Watertube (P), add extra engineering, obtain	16852	16910	39025	42330	64,320	68,050	13280	15,475	55,360	41,095	50765	58,750	9720	15130	25,775	40870	37845	57898
	17,350	16,910	41,050	42,530			14080	15,475	57,860	41,095			10,320	15,150	24,770	40,870		

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BOILER CATEGORY: STORAGE

DESIGN FUEL: COAL

SERVICE FUEL	LOW BTU GAS						MED BTU GAS				NAT GAS					
	10-(25)-50		51-(75)-100		101-(150)-250		10-(25)-50		51-(75)-100		101-(150)-250		10-(25)-50		51-(75)-100		101-(150)-250	
	E	I	E	I	E	I	E	I	E	I	E	I	E	I	E	I	E	I
WELDING ALLOWANCE	1750	480	2500	800	(2) 4200	1700	(1) 1350	480	(1) 2250	600	(2) 4950	720	(1) 2500	980	(1) 2250	600	(1) 4950	720
REGISTERS(S)	1862	640	2675	1000	5870	1500	1920	500	5270	700	5000	1250	1200	900	2870	520	5000	1800
SS GAS P. PIPE (W CLAIM RELAMORTIZ-ING)	1857	160	1800	400	3600	900	600	160	1500	480	3000	800	900	160	1900	420	3000	1800
FUEL LOSS PILOT (300,000 BTU/H)	900	80	1400	80	1400	400	450	100	800	80	800	120	400	80	900	80	800	120
THROTTLE TUBES	600	480	1320	780	1800	1200	450	150	500	200	800	1440	450	460	820	1080	1600	1800
TOOL LOG	—	—	—	—	1750	—	—	—	—	—	—	—	1400	—	—	—	1400	—
M.W. MAINTENANCE	450	320	750	400	1000	500	300	200	750	250	1500	400	550	—	—	—	1400	—
BURNER MANAGEMENT	5200	2000	8950	3560	18500	4920	4150	1720	6800	2010	15050	4870	3601	1120	6650	2060	13860	4920
LEAK TEST	1600	800	1650	800	3800	1200	1200	400	2200	800	3800	1200	1350	800	2450	800	3500	1800
LEAK TEST VENT	1150	640	1500	960	3150	1320	950	320	1600	640	3150	960	850	720	1750	640	3150	1920
GAS FUEL PIPING	5950	1440	9200	1800	18500	1960	5250	1440	9200	1440	18500	1920	5250	1440	9200	1440	18500	1920
PILOT GAS	710	480	710	480	1500	760	710	480	710	480	1500	760	850	480	1100	480	1500	960
MAIN GAS	5220	1200	3130	1600	10450	4000	1220	850	2820	1120	6850	2820	1400	1000	3250	1120	6850	3200
SUPPLY PIPING	600	480	2940	840	5800	2480	640	400	1940	850	5800	2480	3500	24,720	640	1400	1940	850	3500	2480
RETURN PIPING	—	—	—	—	5700	2600	—	—	—	—	—	—	400	1200	—	—	—	—	400	1520
COMBUSTION CONTROLS	3,150	5780	6600	10,830	20,812	8,710	1940	5460	4850	10,150	18885	31810	1695	5240	3870	9910	9650	30810
IGNITION	2000	1080	2700	1080	2850	1140	2000	1080	2700	1080	2850	1140	2700	1080	2700	1080	2850	1140
CROSS & ORIFICE	1600	960	1100	880	1905	1440	1400	880	1100	880	1625	1680	1100	880	1100	880	1705	1440
FD	900	480	3200	960	5000	1520	2000	600	3600	960	5200	3120	2200	600	3200	960	5200	1520
ID	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
EQUIPMENT REMOVAL	2000	600	3200	960	5200	1520	2000	600	3200	960	5200	1800	2200	960	3600	960	5200	1800
GANTRY	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ELEVATE BOILER MUD	—	5200	—	16,000	—	15,600	—	5200	—	16,000	—	6,000	—	5200	—	10,000	—	15,600
ENGINEERING	—	3200	—	16,000	—	15,600	—	5200	—	16,000	—	15,600	—	5200	—	10,000	—	15,600
ERECTION SUPERVISION	6000	—	9800	—	18,500	—	6000	—	9000	—	17,500	—	6700	—	9,800	—	16,000	—
SUNDRY MISC	—	3200	—	5200	—	9200	—	3,000	—	5200	—	9200	—	5200	—	5200	—	9200
Σ 8,12,18,21,23,27,29,31,33,35,37	34,250	34,780	54,600	54,970	75,435	101,490	23,240	34,180	32,200	61,460	94,460	160,880	42,245	32,280	58,870	57,670	52,875	99,460

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POWER PLANT COST: WATERTOWN

SYSTEM FOR PLAN

SUBSTATION EQUIPMENT	5 (75)	LBG	101 (100)-250		251-(300)-500		501-(525)-1000		MVA 1001-(1050)-2500		251-(300)-500		51-(75)-100		NATURAL GAS 101-(125)-250		451-(500)-1000	
	#	$	E	I	E	I	E	I	E	I	E	I	E	I	E	I	E	I
SWGR C.B. (MAIN HEAT SHIELD)	(4) 2250	360	(6) 3450	5300	(10) 7850	9800	(12) 9200	12000	(6) 4500	5400	(4) 3000	3600	(2) 1500	1800	(2) 1800	2400	(3) 3000	3900
CONTROL PLANT	600	480	900	960	1500	1500	1800	1800	900	900	1050	1200	750	900	1500	1800	1500	1950
1 LOTS (BUSWORK - SWITCHGEAR)	960	1080	1600	1800	2400	2700	3000	3600	1200	1350	1500	1800	1000	1200	1500	1800	2400	3120
MISC MAT.	540	480	675	600	1000	900	1200	1200	450	450	600	600	300	360	450	540	600	780
Σ =1	3550	3120	5625	8660	12750	14900	15200	18600	6150	8100	6150	8100	3550	4260	5250	6540	7500	9750
SERVICE MANAGEMENT - NAV																		
- TRIO SYSTEM																		
LINING: L.G.P.	450	600	1200	1500	1500	2000	2250	3000	1500	2000								
FDA	100	80	800	1000	800	1000	1000	1250	1000	1250	1875	2350	600	750	1200	1500	1800	2250
PURE AIR	120	96	160	200	160	200	200	250	200	250	800	1000	480	600	960	1200	1440	1800
	150	120	200	250	200	250	250	312	250	312	1000	1250	600	750	1200	1500	1800	2250
INJ. AIR	100	80	133	166	133	166	166	208	166	208	666	832	400	500	800	1000	1200	1500
FUEL PUMP	75	60	100	125	100	125	125	156	125	156								
FD 9.3 SINGLE PASS 28.75	150	120	200	250	200	250	250	312	250	312								
MISC	75	60	100	125	100	125	125	156	125	156								
Σ =14	1220	1116	2793	3616	3193	4116	4366	5644	3616	4644	4341	5432	2080	2600	3960	5200	6240	7800
FUEL FUEL PIPE																		
PILOT GAS	110	88	220	264	330	396	440	528	440	528	660	792	330	396	440	528	660	792
MAIN GAS	3150	1260	6300	2520	9450	3780	12600	5040	12600	5040	18900	7560	2700	1080	3600	1440	5400	2160
SUPPLY PIPING	2742	2742	5484	5484	8226	8226	10968	10968	10968	10968	16452	16452	2350	2350	3134	3134	4701	4701
SUPPLY (DRAWING P.P 06)	—	—	1200	1200	1800	1800	2400	2400	2400	2400	3600	3600	1200	1200	1600	1600	2400	2400
	6002	4090	13204	9468	19806	14202	26408	18936	26408	18936	39612	28404	6580	5026	8774	6702	13161	10053
MISC. TO CONTROLS	2700	1080	2850	1140	3850	1540	4900	2000	2462	1642	3700	1200	1300	520	2350	940	2900	1160
INSTRUMENTATION	1100	880	1425	1140	1875	1500	1100	880	1025	1025	1875	1500	1100	880	1425	1140	1875	1500
PAINT:																		
F.P	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
I.D.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
EQUIPMENT REMOVAL	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
FURNACE, BOILER MOD.	—	5000	—	10000	—	20000	—	5000	—	10000	—	20000	—	5000	—	10000	—	20000
EXCAVATIONS	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ERECTION SUPERVISION	9720	—	10,440	—	18000	—	38000	—	9576	—	12960	—	3800	—	9000	—	10700	—
START-UP SERVICE	—	1800	—	3850	—	6000	—	1450	—	3700	—	6000	—	1400	—	3850	—	6000
	—	1000	—	1750	—	2500	—	1000	—	1750	—	2000	—	1000	—	1750	—	2500
Σ 5,15,22,4,9,8,1,3,7,2,6	26872	18136	44085	45770	82140	68170	128552	107668	61,960	92,685	69415	67,230	15571	16430	34125	42178	52,975	65750

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APPENDIX D

METRIC SYSTEM CONVERSION FACTORS

Although EPA's policy is to use the metric system in all of its documentation, certain non-metric units are used in this report for convenience. Readers more familiar with the metric system may use the following to convert to that system:

Non-Metric Unit	Multiplied By	Yields Metric Unit
in	2.540	cm
ft	0.3048	m
ft^2	9.3×10^{-2}	m^2
ft^3	28.317	liter
gal.	3.785	liter
lb.	0.454	kg
ton	907.185	kg
centistoke	10^{-6}	m^2/sec
°F	5/9(°F-32)	°C
Btu	1.055×10^3	joule
Btu/ft^3	37.256	joule/liter